AMENDMENT DATED MAY 19, 2025

to the Official Statement dated April 30, 2025

$945,235,000
Energy Northwest

$258,890,000 Project 1 Electric Revenue Refunding Bonds, Series 2025-A
$404,135,000 Columbia Generating Station Electric Revenue and Refunding Bonds, Series 2025-A
$173,185,000 Project 3 Electric Revenue Refunding Bonds, Series 2025-A

$109,025,000 Columbia Generating Station Electric Revenue Bonds, Series 2025-B (Taxable)
(collectively, the "Series 2025-A/B Bonds")

On May 19, 2025, Moody's Ratings downgraded its underlying rating to "Aa2" (stable outlook) from "Aa1" (negative outlook) on the Series 2025-A/B Bonds.

The "RATINGS" section has been amended as shown below (with the additions underlined and the deletions stricken).

RATINGS

Moody's Ratings ("Moody's"), S&P Global Ratings ("S&P") and Fitch Ratings ("Fitch") have assigned the Series 2025-A/B Bonds the ratings of <u>"Aa2" (stable outlook)</u>~~"Aa1" (negative outlook)~~, "AA-" (stable outlook) and "AA" (stable outlook), respectively. Ratings were applied for by Energy Northwest and certain information was supplied by Energy Northwest and Bonneville to such rating agencies to be considered in evaluating the Series 2025-A/B 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or all of such ratings will be retained for any given period of time or that the same will not be revised downward or withdrawn entirely by the rating agency furnishing the same if, in its judgment, circumstances so warrant.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 or marketability of the Series 2025-A/B Bonds.

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NEW ISSUE – BOOK-ENTRY ONLY

Series 2025-A Bonds: *In the opinion of Orrick, Herrington & Sutcliffe LLP, Special Tax Counsel, based upon an analysis of existing laws, regulations, rulings and court decisions, and assuming, among other matters, the accuracy of certain representations and compliance with certain covenants, interest on the Series 2025-A Bonds is excluded from gross income for federal income tax purposes under Title XIII of the Tax Reform Act of 1986, as amended (the "1986 Act"), Section 103 of the Internal Revenue Code of 1954, as amended (the "1954 Code") and Section 103 of the Internal Revenue Code of 1986, as amended (the "1986 Code"). In the further opinion of Special Tax Counsel, interest on the Series 2025-A Bonds is not a specific preference item for purposes of the federal individual alternative minimum tax. Special Tax Counsel observes that interest on the Series 2025-A Bonds included in adjusted financial statement income of certain corporations is not excluded from the federal corporate alternative minimum tax. See "TAX MATTERS—SERIES 2025-A BONDS" herein.*

Series 2025-B (Taxable) Bonds: *In the opinion of Orrick, Herrington & Sutcliffe LLP, Special Tax Counsel, interest on the Series 2025-B (Taxable) Bonds is not excluded from gross income for federal income tax purposes pursuant to Title XIII of the 1986 Act, Section 103 of the 1954 Code, or Section 103 of the 1986 Code. See "TAX MATTERS—SERIES 2025-B (TAXABLE) BONDS" herein.*

Special Tax Counsel expresses no opinion regarding any other tax consequences related to the ownership or disposition of, or the amount, accrual or receipt of interest on, the Series 2025-A/B Bonds. See "TAX MATTERS" herein.

ENERGY NORTHWEST

$945,235,000
ENERGY NORTHWEST

$258,890,000 Project 1 Electric Revenue Refunding Bonds, Series 2025-A
$404,135,000 Columbia Generating Station Electric Revenue and Refunding Bonds, Series 2025-A
$173,185,000 Project 3 Electric Revenue Refunding Bonds, Series 2025-A

$109,025,000 Columbia Generating Station Electric Revenue Bonds, Series 2025-B (Taxable)

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

The Series 2025-A Bonds and the Series 2025-B (Taxable) Bonds (together, the "Series 2025-A/B Bonds") are being issued for the purpose of refunding certain Electric Revenue Bonds issued by Energy Northwest, as more fully described herein. In addition, the Columbia 2025-A/B Bonds may be issued to finance (directly or indirectly through repayment of a bond anticipation note) a portion of fuel related costs and certain additions and improvements to the Columbia Generating Station, all as more fully described herein. See "PURPOSE OF ISSUANCE" herein.

The Series 2025-A/B Bonds will be issued in fully registered form, registered in the name of Cede & Co., as registered owner and nominee for The Depository Trust Company, New York, New York ("DTC"). DTC will act as securities depository for the Series 2025-A/B Bonds. Individual purchases will be made in book-entry form, in denominations of $5,000 and integral multiples thereof. So long as Cede & Co. is the registered owner of the Series 2025-A/B Bonds and nominee of DTC, references herein to holders or registered owners shall mean Cede & Co. and shall not mean the beneficial owners of the Series 2025-A/B Bonds. Principal of the Series 2025-A/B Bonds is payable at the designated office of The Bank of New York Mellon Trust Company, N.A., as Trustee for the Series 2025-A/B Bonds. Interest on the Series 2025-A/B Bonds is payable semiannually on January 1 and July 1 of each year, commencing January 1, 2026. As long as Cede & Co. is the registered owner as nominee of DTC, payments on the Series 2025-A/B Bonds will be made to such registered owner, and disbursement of such payments will be the responsibility of DTC and DTC Participants as described herein. See "DESCRIPTION OF THE SERIES 2025-A/B BONDS—GENERAL—Book-Entry System; Transferability and Registration" and Appendix I—"BOOK-ENTRY SYSTEM" herein.

The Series 2025-A/B Bonds are subject to redemption prior to maturity as set forth herein. See "DESCRIPTION OF THE SERIES 2025-A/B BONDS—REDEMPTION" *herein.*

The Series 2025-A/B Bonds are special revenue obligations of Energy Northwest, payable solely from the sources described herein, including amounts derived pursuant to Net Billing Agreements with the United States of America, Department of Energy, acting by and through the Administrator of the

BONNEVILLE POWER ADMINISTRATION

("Bonneville") from net billing credits and from cash payments from the Bonneville Fund, as described herein. Bonneville's obligations under the Net Billing Agreements are not general obligations of the United States of America and are not secured by the full faith and credit of the United States of America. The Series 2025-A/B Bonds do not constitute an obligation of the State of Washington or of any political subdivision thereof, other than Energy Northwest. Energy Northwest has no taxing power. Project 1, the Columbia Generating Station and Project 3 are separate projects of Energy Northwest, and each Series of the Series 2025-A/B Bonds are payable solely from the revenues of the Project related to such Series. See "SECURITY FOR THE NET BILLED BONDS" and Appendix A—"THE BONNEVILLE POWER ADMINISTRATION" herein.

MATURITY SCHEDULE – See Inside Cover Pages

The Series 2025-A/B Bonds are offered when, as, and if issued and received by the Underwriters, subject to the approval of legality by Foster Garvey P.C., Seattle, Washington, Bond Counsel to Energy Northwest, and to certain other conditions. Certain tax matters will be passed upon by Orrick, Herrington & Sutcliffe LLP, Special Tax Counsel to Bonneville. Certain legal matters will be passed upon for Energy Northwest by its Office of General Counsel and for Bonneville by its General Counsel and by its Special Counsel, Orrick, Herrington & Sutcliffe LLP. Certain legal matters will be passed upon for the Underwriters by Norton Rose Fulbright US LLP, New York, New York, Counsel to the Underwriters. It is expected that the Series 2025-A/B Bonds will be available for delivery through the facilities of DTC on or about May 21, 2025.

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

BofA Securities

April 30, 2025

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

THE SERIES 2025-A BONDS

$258,890,000
PROJECT 1 ELECTRIC REVENUE REFUNDING BONDS, SERIES 2025-A

Year (July 1)	Amount	Interest Rate	Yield	Price	CUSIP No.*
2027	$ 18,850,000	5.000%	3.100%	103.850%	29270C6W0
2028	29,140,000	5.000	3.100	105.590	29270C6X8
2032	50,000,000	5.000	3.310	110.626	29270C6Y6
2033	25,000,000	5.000	3.370	111.480	29270C6Z3
2034	35,000,000	5.000	3.480	111.777	29270C7A7
2035	50,450,000	5.000	3.560	112.134	29270C7B5
2040	50,450,000	5.000	4.010	108.158**	29270C7C3

$404,135,000
COLUMBIA GENERATING STATION ELECTRIC REVENUE AND REFUNDING BONDS, SERIES 2025-A

Year (July 1)	Amount	Interest Rate	Yield	Price	CUSIP No.*
2029	$ 25,000,000	5.000%	3.130%	107.157%	29270C6H3
2030	26,085,000	5.000	3.170	108.569	29270C6J9
2031	26,885,000	5.000	3.250	109.625	29270C6K6
2032	25,000,000	5.000	3.310	110.626	29270C6L4
2033	25,655,000	5.000	3.370	111.480	29270C6M2
2034	26,940,000	5.000	3.480	111.777	29270C6N0
2035	15,000,000	5.000	3.560	112.134	29270C6P5
2036	15,000,000	5.000	3.680	111.057**	29270C6Q3
2037	15,000,000	5.000	3.790	110.080**	29270C6R1
2038	15,190,000	5.000	3.890	109.202**	29270C6S9
2041	62,795,000	5.000	4.080	107.555**	29270C6T7
2042	62,795,000	5.000	4.150	106.956**	29270C6U4
2043	62,790,000	5.000	4.220	106.361**	29270C6V2

$173,185,000
PROJECT 3 ELECTRIC REVENUE REFUNDING BONDS, SERIES 2025-A

Year (July 1)	Amount	Interest Rate	Yield	Price	CUSIP No.*
2026	$ 63,540,000	5.000%	3.060%	102.100%	29270C7D1
2031	45,000,000	5.000	3.250	109.625	29270C7E9
2039	64,645,000	5.000	3.960	108.592**	29270C7F6

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* The CUSIP numbers are provided by CUSIP Global Services ("CGS"), managed on behalf of the American Bankers Association by FactSet Research Systems Inc. The CUSIP numbers are not intended to create a database and do not serve in any way as a substitute for CUSIP service. CUSIP numbers are provided for convenience and reference only, and are subject to change. Neither Energy Northwest nor the Underwriters take responsibility for the accuracy of the CUSIP numbers.

** Priced to the July 1, 2035 par call date.

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

THE SERIES 2025-B (TAXABLE) BONDS

$109,025,000
COLUMBIA GENERATING STATION ELECTRIC REVENUE BONDS, SERIES 2025-B (TAXABLE)

Year (July 1)	Amount	Interest Rate	Yield	Price	CUSIP No.*
2026	$ 32,365,000	4.217%	4.217%	100.000%	29270C6E0
2029	24,805,000	4.217	4.217	100.000	29270C6F7
2030	51,855,000	4.317	4.317	100.000	29270C6G5

* The CUSIP numbers are provided by CUSIP Global Services ("CGS"), managed on behalf of the American Bankers Association by FactSet Research Systems Inc. The CUSIP numbers are not intended to create a database and do not serve in any way as a substitute for CUSIP service. CUSIP numbers are provided for convenience and reference only, and are subject to change. Neither Energy Northwest nor the Underwriters take responsibility for the accuracy of the CUSIP numbers.

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

Executive Board Members

John Saven, Chair	Janet Herrin
Curt Knapp, Vice Chair	Johnny (Jack) Janda
Bill Gordon, Secretary	Dave McKenzie
James Moss, Assistant Secretary	Bill Pitesa
Arie Callaghan	Tim Sheldon
Marc Daudon	

Administrative Staff

Chief Executive Officer	Robert E. Schuetz
Chief of Executive Projects	Marcus A. Harris
Executive Vice President/Chief Nuclear Officer	William G. Hettel
Vice President for Corporate Governance; General Counsel	Scott A. Vance
Vice President for Corporate Finance, Chief Financial and Risk Officer	Cristina M. Reyff
Vice President for Energy Services and Development	Greg V. Cullen
Vice President for Corporate Support Services	Dawn M. Sileo

Financial Advisor

PFM Financial Advisors LLC

Bond and Disclosure Counsel

Foster Garvey P.C.

Trustee for the Series 2025-A/B Bonds

The Bank of New York Mellon Trust Company, N.A.

BONNEVILLE POWER ADMINISTRATION
P.O. Box 3621
Portland, Oregon 97208
Telephone (503) 230-3000

Administrator and Chief Executive Officer	John L. Hairston
Chief Operating Officer	Vacant*
Chief Administrative Officer	Robin R. Furrer
Chief Workforce and Strategy Officer	Daniel M. James
Senior Vice President, Power Services	Suzanne B. Cooper
Senior Vice President, Transmission Services	Vacant*
Executive Vice President and Chief Financial Officer	Vacant*
Executive Vice President and Chief Information Officer	Chris K. Wilk
Executive Vice President of Compliance, Audit and Risk Management	Tom A. McDonald
Executive Vice President, Environment, Fish and Wildlife	Scott G. Armentrout
Executive Vice President and General Counsel	Marcus H. Chong Tim

Special Counsel and Special Tax Counsel

Orrick, Herrington & Sutcliffe LLP

* For more details, see Appendix A—"THE BONNEVILLE POWER ADMINISTRATION—CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Change in Administration" in this Official Statement.

No dealer, broker, salesperson or other person has been authorized by Energy Northwest or by the Underwriters to give any information or to make any representations in connection with the issuance and sale of the Series 2025-A/B Bonds, other than as contained in this Official Statement, and, if given or made, such other information or representations must not be relied upon as having been authorized by Energy Northwest or the Underwriters. This Official Statement does not constitute an offer to sell or the solicitation of an offer to buy by, nor shall there be any sale of the Series 2025-A/B 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.

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

None of the information herein was provided by the Participants (as defined under "SECURITY FOR THE NET BILLED BONDS—NET BILLING AND RELATED AGREEMENTS—General") or the Trustee and none of such entities participated in the preparation of this Official Statement. This Official Statement has not been submitted to such entities for review, comment or approval.

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

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

References to website addresses presented herein are for informational purposes only and may be in the form of a hyperlink solely for the reader's convenience. Unless specified otherwise, such websites and the information or links contained therein are not incorporated into, and are not part of, this Official Statement for purposes of, and as that term is defined in, Securities and Exchange Commission Rule 15c2-12.

INFORMATION CONCERNING OFFERING RESTRICTIONS IN CERTAIN JURISDICTIONS OUTSIDE THE UNITED STATES

NEITHER ENERGY NORTHWEST NOR BONNEVILLE MAKES ANY REPRESENTATION AS TO THE ACCURACY, COMPLETENESS OR ADEQUACY OF THE INFORMATION UNDER THIS CAPTION. REFERENCES UNDER THIS CAPTION TO "BONDS" OR "SECURITIES" MEAN THE SERIES 2025-A/B BONDS OFFERED HEREBY. THESE LEGENDS ARE BEING PROVIDED SOLELY FOR THE CONVENIENCE OF THE UNDERWRITERS. COMPLIANCE WITH ANY RULES OR RESTRICTIONS OF ANY JURISDICTION RELATING TO THE OFFERING, SOLICITATION AND/OR SALE OF THE SERIES 2025-A/B BONDS IS THE RESPONSIBILITY OF THE UNDERWRITERS AND NEITHER ENERGY NORTHWEST NOR BONNEVILLE SHALL HAVE ANY RESPONSIBILITY OR LIABILITY IN CONNECTION THEREWITH.

IN CONNECTION WITH OFFERINGS AND SALES OF THE SERIES 2025-A/B BONDS, NO ACTION HAS BEEN TAKEN BY ENERGY NORTHWEST OR BONNEVILLE THAT WOULD PERMIT A PUBLIC OFFERING OF THE SERIES 2025-A/B BONDS, OR POSSESSION OR DISTRIBUTION OF ANY INFORMATION RELATING TO THE PRICING OF THE SERIES 2025-A/B BONDS, THIS OFFICIAL STATEMENT OR ANY OTHER OFFERING OR PUBLICITY MATERIAL RELATING TO THE SERIES 2025-A/B BONDS, IN ANY NON-U.S. JURISDICTION WHERE ACTION FOR THAT PURPOSE IS REQUIRED.

MINIMUM UNIT SALES

THE SERIES 2025-A/B BONDS WILL TRADE AND SETTLE ON A UNIT BASIS (ONE UNIT EQUALING ONE BOND OF $5,000 PRINCIPAL AMOUNT). FOR ANY SALES MADE OUTSIDE THE UNITED STATES, THE MINIMUM PURCHASE AND TRADING AMOUNT IS 30 UNITS (BEING 30 BONDS IN AN AGGREGATE PRINCIPAL AMOUNT OF $150,000).

NOTICE TO PROSPECTIVE INVESTORS IN CANADA

NO PROSPECTUS HAS BEEN FILED WITH ANY SECURITIES COMMISSION OR SIMILAR REGULATORY AUTHORITY IN CANADA IN CONNECTION WITH THE OFFERING OF THE SERIES 2025-A/B BONDS. NO SECURITIES COMMISSION OR SIMILAR REGULATORY AUTHORITY IN CANADA HAS REVIEWED OR IN ANY WAY PASSED UPON THIS OFFICIAL STATEMENT OR THE MERITS OF THE SERIES 2025-A/B BONDS AND ANY REPRESENTATION TO THE CONTRARY IS AN OFFENCE. THIS OFFICIAL STATEMENT IS NOT, AND UNDER NO CIRCUMSTANCES IS TO BE CONSTRUED AS, AN ADVERTISEMENT OR A PUBLIC OFFERING OF THE SERIES 2025-A/B BONDS IN CANADA.

THE SERIES 2025-A/B BONDS MAY BE SOLD IN CANADA ONLY TO PURCHASERS PURCHASING, OR DEEMED TO BE PURCHASING, AS PRINCIPAL THAT ARE ACCREDITED INVESTORS, AS DEFINED IN NATIONAL INSTRUMENT 45-106 PROSPECTUS EXEMPTIONS OR SUBSECTION 73.3(1) OF THE SECURITIES ACT (ONTARIO), AND ARE PERMITTED CLIENTS, AS DEFINED IN NATIONAL INSTRUMENT 31-103 REGISTRATION REQUIREMENTS, EXEMPTIONS AND ONGOING REGISTRANT OBLIGATIONS. ANY RESALE OF THE SERIES 2025-A/B BONDS MUST BE MADE IN ACCORDANCE WITH AN EXEMPTION FROM, OR IN A TRANSACTION NOT SUBJECT TO, THE PROSPECTUS REQUIREMENTS OF APPLICABLE SECURITIES LAWS.

SECURITIES LEGISLATION IN CERTAIN PROVINCES OR TERRITORIES OF CANADA MAY PROVIDE A PURCHASER WITH REMEDIES FOR RESCISSION OR DAMAGES IF THIS OFFICIAL STATEMENT (INCLUDING ANY AMENDMENT THERETO) CONTAINS A MISREPRESENTATION, PROVIDED THAT THE REMEDIES FOR RESCISSION OR DAMAGES ARE EXERCISED BY THE PURCHASER WITHIN THE TIME LIMIT PRESCRIBED BY THE SECURITIES LEGISLATION OF THE PURCHASER'S PROVINCE OR TERRITORY. THE PURCHASER SHOULD REFER TO ANY APPLICABLE PROVISIONS OF THE SECURITIES LEGISLATION OF THE PURCHASER'S PROVINCE OR TERRITORY FOR PARTICULARS OF THESE RIGHTS OR CONSULT WITH A LEGAL ADVISOR.

PURSUANT TO SECTION 3A.3 OF NATIONAL INSTRUMENT 33-105 UNDERWRITING CONFLICTS (NI 33-105), THE UNDERWRITERS ARE NOT REQUIRED TO COMPLY WITH THE DISCLOSURE REQUIREMENTS OF NI 33-105 REGARDING UNDERWRITER CONFLICTS OF INTEREST IN CONNECTION WITH THIS OFFERING.

NOTICE TO PROSPECTIVE INVESTORS IN THE EUROPEAN ECONOMIC AREA ("EEA")

PROHIBITION ON SALES TO EU RETAIL INVESTORS

THE SERIES 2025-A/B BONDS ARE NOT INTENDED TO BE OFFERED, SOLD OR OTHERWISE MADE AVAILABLE TO AND WILL NOT BE OFFERED, SOLD OR OTHERWISE MADE AVAILABLE TO ANY EU RETAIL INVESTOR IN THE EUROPEAN ECONOMIC AREA ("EEA"). FOR PURPOSES OF THIS PROVISION:

(A) THE EXPRESSION "EU RETAIL INVESTOR" MEANS A PERSON WHO IS ONE (OR MORE) OF THE FOLLOWING:

(I) A RETAIL CLIENT AS DEFINED IN POINT (11) OF ARTICLE 4(1) OF DIRECTIVE 2014/65/EU (AS AMENDED, "MIFID II"); OR

(II) A CUSTOMER WITHIN THE MEANING OF DIRECTIVE (EU) 2016/97, AS AMENDED, WHERE THAT CUSTOMER WOULD NOT QUALIFY AS A PROFESSIONAL CLIENT AS DEFINED IN POINT (10) OF ARTICLE 4(1) OF MIFID II; OR

(III) NOT A QUALIFIED INVESTOR (“EU QUALIFIED INVESTOR”) AS DEFINED IN ARTICLE 2 OF REGULATION (EU) 2017/1129 (AS AMENDED, THE “EU PROSPECTUS REGULATION”); AND

(B) THE EXPRESSION “OFFER” INCLUDES THE COMMUNICATION IN ANY FORM AND BY ANY MEANS OF SUFFICIENT INFORMATION ON THE TERMS OF THE OFFER AND THE SERIES 2025-A/B BONDS TO BE OFFERED SO AS TO ENABLE AN INVESTOR TO DECIDE TO PURCHASE OR SUBSCRIBE FOR THE SERIES 2025-A/B BONDS.

CONSEQUENTLY, NO KEY INFORMATION DOCUMENT REQUIRED BY REGULATION (EU) NO 1286/2014 (AS AMENDED, THE “EU PRIIPS REGULATION”) FOR OFFERING OR SELLING THE SERIES 2025-A/B BONDS OR OTHERWISE MAKING THEM AVAILABLE TO EU RETAIL INVESTORS IN THE EEA HAS BEEN PREPARED AND THEREFORE OFFERING OR SELLING THE SERIES 2025-A/B BONDS OR OTHERWISE MAKING THEM AVAILABLE TO ANY EU RETAIL INVESTOR IN THE EEA MAY BE UNLAWFUL UNDER THE EU PRIIPS REGULATION.

OTHER EEA OFFERING RESTRICTIONS

THIS OFFICIAL STATEMENT IS NOT A PROSPECTUS FOR THE PURPOSES OF THE EU PROSPECTUS REGULATION. THIS OFFICIAL STATEMENT HAS BEEN PREPARED ON THE BASIS THAT ANY OFFER OF SERIES 2025-A/B BONDS IN THE EEA WILL ONLY BE MADE TO EU QUALIFIED INVESTORS. ACCORDINGLY, ANY PERSON MAKING OR INTENDING TO MAKE AN OFFER IN THE EEA OF SERIES 2025-A/B BONDS MAY ONLY DO SO WITH RESPECT TO EU QUALIFIED INVESTORS. NONE OF ENERGY NORTHWEST, BONNEVILLE OR ANY OF THE UNDERWRITERS HAVE AUTHORIZED, NOR DO THEY AUTHORIZE, THE MAKING OF ANY OFFER OF SERIES 2025-A/B BONDS IN THE EEA OTHER THAN TO EU QUALIFIED INVESTORS.

NOTICE TO PROSPECTIVE INVESTORS IN THE UNITED KINGDOM

PROHIBITION ON SALES TO UK RETAIL INVESTORS

THE SERIES 2025-A/B BONDS ARE NOT INTENDED TO BE OFFERED, SOLD OR OTHERWISE MADE AVAILABLE TO AND WILL NOT BE OFFERED, SOLD OR OTHERWISE MADE AVAILABLE TO ANY UK RETAIL INVESTOR IN THE UNITED KINGDOM (“UK”). FOR PURPOSES OF THIS PROVISION:

(A) THE EXPRESSION “UK RETAIL INVESTOR” MEANS A PERSON WHO IS ONE (OR MORE) OF THE FOLLOWING:

(I) A RETAIL CLIENT AS DEFINED IN POINT (8) OF ARTICLE 2 OF COMMISSION DELEGATED REGULATION (EU) 2017/565, AS IT FORMS PART OF UK DOMESTIC LAW BY VIRTUE OF THE EUROPEAN UNION (WITHDRAWAL) ACT 2018 (AS AMENDED, THE “EUWA”) AND AS AMENDED;OR

(II) A CUSTOMER WITHIN THE MEANING OF THE PROVISIONS OF THE UK FINANCIAL SERVICES AND MARKETS ACT 2000 (AS AMENDED, “FSMA”) AND ANY RULES OR REGULATIONS MADE UNDER FSMA (SUCH RULES AND REGULATIONS AS AMENDED) TO IMPLEMENT DIRECTIVE (EU) 2016/97, WHERE THAT CUSTOMER WOULD NOT QUALIFY AS A PROFESSIONAL CLIENT, AS DEFINED IN POINT (8) OF ARTICLE 2(1) OF REGULATION (EU) NO 600/2014, AS IT FORMS PART OF UK DOMESTIC LAW BY VIRTUE OF THE EUWA AND AS AMENDED (“UK MIFIR”); OR

(III) NOT A QUALIFIED INVESTOR (“UK QUALIFIED INVESTOR”) AS DEFINED IN ARTICLE 2 OF REGULATION (EU) 2017/1129, AS IT FORMS PART OF UK DOMESTIC LAW BY VIRTUE OF THE EUWA AND AS AMENDED (THE “UK PROSPECTUS REGULATION”); AND

(B) THE EXPRESSION “OFFER” INCLUDES THE COMMUNICATION IN ANY FORM AND BY ANY MEANS OF SUFFICIENT INFORMATION ON THE TERMS OF THE OFFER AND THE SERIES 2025-A/B BONDS TO BE OFFERED SO AS TO ENABLE AN INVESTOR TO DECIDE TO PURCHASE OR SUBSCRIBE FOR THE SERIES 2025-A/B BONDS.

CONSEQUENTLY, NO KEY INFORMATION DOCUMENT REQUIRED BY REGULATION (EU) NO 1286/2014 (AS AMENDED), AS IT FORMS PART OF UK DOMESTIC LAW BY VIRTUE OF THE EUWA AND AS AMENDED (THE “UK PRIIPS REGULATION”) FOR OFFERING OR SELLING THE SERIES 2025-A/B BONDS OR OTHERWISE MAKING THEM AVAILABLE TO UK RETAIL INVESTORS TN THE UK HAS BEEN PREPARED AND THEREFORE OFFERING OR SELLING THE SERIES 2025-A/B BONDS OR OTHER WISE MAKING THEM AVAILABLE TO ANY UK RETAIL INVESTOR IN THE UK MAY BE UNLAWFUL UNDER THE UK PRIIPS REGULATION.

OTHER UK OFFERING RESTRICTIONS

THIS OFFICIAL STATEMENT IS NOT A PROSPECTUS FOR THE PURPOSES OF THE UK PROSPECTUS REGULATION. THIS OFFICIAL STATEMENT HAS BEEN PREPARED ON THE BASIS THAT ANY OFFER OF SERIES 2025-A/B BONDS IN THE UK WILL ONLY BE MADE TO UK QUALIFIED INVESTORS. ACCORDINGLY, ANY PERSON MAKING OR INTENDING TO MAKE AN OFFER IN THE UK OF SERIES 2025-A/B BONDS MAY ONLY DO SO WITH RESPECT TO UK QUALIFIED INVESTORS. NONE OF ENERGY NORTHWEST, BONNEVILLE OR ANY OF THE UNDERWRITERS HAVE AUTHORIZED, NOR DO THEY AUTHORIZE, THE MAKING OF ANY OFFER OF SERIES 2025-A/B BONDS IN THE UK OTHER THAN TO UK QUALIFIED INVESTORS.

OTHER UK REGULATORY RESTRICTIONS

IN THE UK, THIS OFFICIAL STATEMENT IS BEING COMMUNICATED ONLY TO AND IS BEING DIRECTED ONLY AT, PERSONS WHO (1) HAVE PROFESSIONAL EXPERIENCE IN MATTERS RELATING TO INVESTMENTS AND WHO FALL WITHIN ARTICLE 19(5) OF THE FINANCIAL SERVICES AND MARKETS ACT 2000 (FINANCIAL PROMOTION) ORDER 2005 (AS AMENDED, THE "FINANCIAL PROMOTION ORDER"), (2) ARE PERSONS FALLING WITHIN ARTICLE 49(2)(A) TO (D) ("HIGH NET WORTH COMPANIES, UNINCORPORATED ASSOCIATIONS ETC.") OF THE FINANCIAL PROMOTION ORDER OR (3) ARE PERSONS TO WHOM IT MAY OTHERWISE LAWFULLY BE COMMUNICATED UNDER SECTION 21 OF FSMA (ALL SUCH PERSONS TOGETHER BEING REFERRED TO AS "RELEVANT PERSONS"). IN THE UK, THIS OFFICIAL STATEMENT MUST NOT BE ACTED ON OR RELIED ON BY PERSONS WHO ARE NOT RELEVANT PERSONS. IN THE UK, ANY INVESTMENT OR INVESTMENT ACTIVITY TO WHICH THIS OFFICIAL STATEMENT RELATES, INCLUDING THE SERIES 2025-A/B BONDS, IS AVAILABLE ONLY TO RELEVANT PERSONS AND WILL BE ENGAGED IN ONLY WITH RELEVANT PERSONS.

NO PERSON MAY COMMUNICATE OR CAUSE TO BE COMMUNICATED ANY INVITATION OR INDUCEMENT TO ENGAGE IN INVESTMENT ACTIVITY (WITHIN THE MEANING OF SECTION 21 OF FSMA) RECEIVED BY IT IN CONNECTION WITH THE ISSUE OR SALE OF THE SERIES 2025-A/B BONDS OTHER THAN IN CIRCUMSTANCES IN WHICH SECTION 21(1) OF FSMA DOES NOT APPLY.

POTENTIAL INVESTORS IN THE UK ARE ADVISED THAT ALL, OR MOST, OF THE PROTECTIONS AFFORDED BY THE UK REGULATORY SYSTEM WILL NOT APPLY TO AN INVESTMENT IN THE SERIES 2025-A/B BONDS AND THAT COMPENSATION WILL NOT BE AVAILABLE UNDER THE UK FINANCIAL SERVICES COMPENSATION SCHEME.

NOTICE TO PROSPECTIVE INVESTORS IN SWITZERLAND

PROHIBITION OF SALES TO SWISS RETAIL INVESTORS

THE SERIES 2025-A/B BONDS ARE NOT INTENDED TO BE OFFERED, SOLD OR OTHERWISE MADE AVAILABLE TO AND SHOULD NOT BE OFFERED, SOLD OR OTHERWISE MADE AVAILABLE TO ANY RETAIL INVESTOR IN SWITZERLAND. FOR THESE PURPOSES, A RETAIL INVESTOR MEANS A PERSON WHO IS A RETAIL CLIENT AS DEFINED IN ARTICLE 4 OF THE SWISS FINANCIAL SERVICES ACT ("FINSA").

NO KEY INFORMATION DOCUMENT ACCORDING TO FINSA OR ANY EQUIVALENT DOCUMENT UNDER FINSA HAS BEEN PREPARED IN RELATION TO THE SERIES 2025-A/B BONDS, AND, THEREFORE, THE SERIES 2025-A/B BONDS MAY NOT BE OFFERED OR RECOMMENDED TO RETAIL CLIENTS WITHIN THE MEANING OF FINSA IN SWITZERLAND.

EXEMPTION TO PREPARE A FINSA-COMPLIANT PROSPECTUS

THE OFFERING OF THE SERIES 2025-A/B BONDS IN SWITZERLAND IS EXEMPT FROM THE REQUIREMENT TO PREPARE AND PUBLISH A PROSPECTUS UNDER FINSA BECAUSE SUCH OFFERING IS MADE TO PROFESSIONAL CLIENTS AND INSTITUTIONAL CLIENTS WITHIN THE MEANING OF FINSA ONLY. THIS DOCUMENT DOES NOT CONSTITUTE A PROSPECTUS PURSUANT TO FINSA, AND NO SUCH PROSPECTUS HAS BEEN OR WILL BE PREPARED FOR OR IN CONNECTION WITH THE OFFERING OF THE SERIES 2025-A/B BONDS.

NOTICE TO PROSPECTIVE INVESTORS IN JAPAN

THE SERIES 2025-A/B BONDS HAVE NOT BEEN AND WILL NOT BE REGISTERED PURSUANT TO ARTICLE 4, PARAGRAPH 1 OF THE FINANCIAL INSTRUMENTS AND EXCHANGE ACT OF JAPAN (LAW NO. 25 OF 1948, AS AMENDED ("FIEA")) AND, ACCORDINGLY, NEITHER THE SERIES 2025-A/B BONDS NOR ANY INTEREST IN THEM MAY BE OFFERED OR SOLD, DIRECTLY OR INDIRECTLY, IN JAPAN OR TO, OR FOR THE BENEFIT, OF ANY RESIDENT OF JAPAN OR TO OTHERS FOR RE-OFFERING OR RESALE, DIRECTLY OR INDIRECTLY, IN JAPAN OR TO A RESIDENT OF JAPAN EXCEPT UNDER CIRCUMSTANCES WHICH WILL RESULT IN COMPLIANCE WITH ALL APPLICABLE LAWS, REGULATIONS AND GUIDELINES PROMULGATED BY THE RELEVANT JAPANESE GOVERNMENTAL AND REGULATORY AUTHORITIES AND IN EFFECT AT THE RELEVANT TIME. FOR THE PURPOSES OF THIS PARAGRAPH, "RESIDENT OF JAPAN" MEANS A NATURAL PERSON HAVING HIS/HER PLACE OF DOMICILE OR RESIDENCE IN JAPAN, OR A LEGAL PERSON HAVING ITS MAIN OFFICE IN JAPAN. A BRANCH, AGENCY OR OTHER OFFICE IN JAPAN OF A NON-RESIDENT, IRRESPECTIVE OF WHETHER IT IS LEGALLY AUTHORIZED TO REPRESENT ITS PRINCIPAL OR NOT, SHALL BE DEEMED TO BE A RESIDENT OF JAPAN EVEN IF ITS MAIN OFFICE IS IN ANY COUNTRY OTHER THAN JAPAN. RESIDENT OF JAPAN SHALL EXCLUDE NON-RESIDENTS OF JAPAN, AS SUCH TERM IS DEFINED IN ARTICLE 6, PARAGRAPH 1, SUB- PARAGRAPH 6 OF THE FOREIGN EXCHANGE AND TRADE ACT OF JAPAN (ACT. NO. 228 OF 1949, AS AMENDED).

THE OFFERING OF THE SERIES 2025-A/B BONDS IN JAPAN ARE BEING MADE BY MEANS OF A PRIVATE PLACEMENT TO QUALIFIED INSTITUTIONAL INVESTORS (TEKIKAKU-KIKAN-TOSHIKA) (WITHIN THE MEANING OF SUCH TERM PROVIDED FOR UNDER ARTICLE 2, PARAGRAPH 3, SUB-PARAGRAPH 1 OF THE FIEA AND ARTICLE 10, PARAGRAPH 1 OF THE CABINET OFFICE ORDINANCE CONCERNING DEFINITIONS PROVIDED IN ARTICLE 2 OF THE FINANCIAL INSTRUMENTS AND EXCHANGE ACT IN JAPAN (MINISTRY OF FINANCE ORDINANCE NO. 14, OF 1993, AS AMENDED)) (THE "QIIS"), THE OFFERING OF THE SERIES 2025-A/B BONDS IN JAPAN SHALL BE MADE ON THE CONDITIONS THAT THE SERIES 2025-A/B BONDS SHALL NOT BE TRANSFERRED TO ANY PERSON OTHER THAN QIIS AND A DOCUMENT INCLUDING THE INFORMATION ON THE SERIES 2025-A/B BONDS AND TO BE DELIVERED TO A PROSPECTIVE PURCHASER SHALL STATE THAT THE SERIES 2025-A/B BONDS SHALL NOT BE TRANSFERRED TO ANY PERSON OTHER THAN A QIIS.

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INTRODUCTION

Energy Northwest furnishes this Official Statement, which includes the cover page and inside cover pages hereof and the appendices hereto, in connection with the sale of the Series 2025-A/B Bonds (hereinafter defined). This Introduction is not intended to provide all information material to a prospective purchaser of the Series 2025-A/B Bonds and is qualified in all respects by the more detailed information set forth elsewhere in this Official Statement. Unless otherwise specifically defined, certain capitalized terms used in this Introduction have the meanings given to such terms elsewhere in this Official Statement.

Energy Northwest, a municipal corporation and a joint operating agency of the State of Washington, proposes to issue $258,890,000 aggregate principal amount of Project 1 Electric Revenue Refunding Bonds, Series 2025-A (the "Project 1 2025-A Bonds"), $404,135,000 aggregate principal amount of Columbia Generating Station Electric Revenue and Refunding Bonds, Series 2025-A (the "Columbia 2025-A Bonds") and $173,185,000 aggregate principal amount of Project 3 Electric Revenue Refunding Bonds, Series 2025-A (the "Project 3 2025-A Bonds," and collectively with the Project 1 2025-A Bonds and Columbia 2025-A Bonds, the "Series 2025-A Bonds"), and $109,025,000 aggregate principal amount of Columbia Generating Station Electric Revenue Bonds, Series 2025-B (Taxable) (the "Columbia 2025-B (Taxable) Bonds" or the "Series 2025-B (Taxable) Bonds"). The Series 2025-A Bonds and the Series 2025-B (Taxable) Bonds are collectively referred to herein as the "Series 2025-A/B Bonds."

The Project 1 2025-A Bonds are being issued pursuant to Chapters 39.46, 39.53 and 43.52 of the Revised Code of Washington, as amended (the "Act") and Resolution No. 835 adopted on November 23, 1993 (as amended and supplemented, including by Resolution No. 2192 adopted on March 27, 2025, the "Project 1 Electric Revenue Bond Resolution") for the purpose of refunding certain indebtedness currently outstanding under the Project 1 Electric Revenue Bond Resolution, and financing a portion of the costs of issuing the Project 1 2025-A Bonds. See "PURPOSE OF ISSUANCE." Energy Northwest has other indebtedness currently outstanding under the Project 1 Electric Revenue Bond Resolution, which will be on a parity with the Project 1 2025-A Bonds (the "Project 1 Electric Revenue Bonds"). There are no Project 1 bonds outstanding that have a lien on revenues that is prior to the lien of the Project 1 Electric Revenue Bonds and Energy Northwest has covenanted not to issue any prior lien debt.

The Columbia 2025-A Bonds are being issued pursuant to the Act and Resolution No. 1042 adopted on October 23, 1997 (as amended and supplemented, including by Resolution No. 2193 adopted on March 27, 2025, the "Columbia Electric Revenue Bond Resolution") for the purpose of refunding certain indebtedness currently outstanding under the Columbia Electric Revenue Bond Resolution, financing the costs of certain additions and improvements to the Columbia Generating Station (also referred to herein as "Columbia"), and financing a portion of the costs of issuing the Columbia 2025-A Bonds. The Columbia 2025-B (Taxable) Bonds (and together with the Columbia 2025-A Bonds, the "Columbia 2025-A/B Bonds") are being issued pursuant to the Act and the Columbia Electric Revenue Bond Resolution for the purpose (directly or indirectly through repayment of a bond anticipation note as further described under "PURPOSE OF ISSUANCE") of paying fuel related costs and certain additions and improvements to the Columbia Generating Station, and financing a portion of the costs of issuing the issuing the Columbia 2025-B (Taxable) Bonds and financing a portion of the costs of issuing the Columbia 2025-A Bonds. See "PURPOSE OF ISSUANCE." Energy Northwest has other indebtedness currently outstanding under the Columbia Electric Revenue Bond Resolution, which will be on a parity with the Columbia 2025-A/B Bonds (the "Columbia Electric Revenue Bonds"). There are no Columbia bonds outstanding that have a lien on revenues that is prior to the lien of the Columbia Electric Revenue Bonds and Energy Northwest has covenanted not to issue any prior lien debt.

The Project 3 2025-A Bonds are being issued pursuant to the Act and Resolution No. 838 adopted on November 23, 1993 (as amended and supplemented, including by Resolution No. 2194 adopted on March 27, 2025, the "Project 3 Electric Revenue Bond Resolution," and collectively with the Project 1 Electric Revenue Bond Resolution and the Columbia Electric Revenue Bond Resolution, the "Electric Revenue Bond Resolutions") for the purpose of refunding certain indebtedness currently outstanding under the Project 3 Electric Revenue Bond Resolution, and financing a portion of the costs of issuing the Project 3 2025-A Bonds. See "PURPOSE OF ISSUANCE." Energy Northwest has other indebtedness currently outstanding under the Project 3 Electric Revenue Bond Resolution, which will be on a parity with the Project 3 2025-A Bonds (the "Project 3 Electric Revenue Bonds," and collectively with the Project 1 Electric Revenue Bonds and Columbia Electric Revenue Bonds, the "Electric Revenue Bonds"). There are no Project 3 bonds outstanding that have a lien on revenues that is prior to the lien of the Project 3 Electric Revenue Bonds and Energy Northwest has covenanted not to issue any prior lien debt.

The Electric Revenue Bonds, including the Series 2025-A/B Bonds, and any bonds or notes issued pursuant to the hereinafter defined Separate Resolutions are collectively referred to herein as the "Net Billed Bonds."

Energy Northwest has a line of credit that matures on December 16, 2026, pursuant to a Loan Agreement dated December 16, 2024, between Wells Fargo Municipal Capital Strategies, LLC and Energy Northwest (the "2024 Loan Agreement"), in the amount not to exceed $120,000,000 for Columbia. Energy Northwest's obligation to repay advances under the 2024 Loan Agreement is evidenced by a Columbia revolving tax-exempt bond anticipation note and a revolving taxable bond anticipation note (together, the "Columbia 2024A/B Notes"). As of March 31, 2025, Energy Northwest had a balance outstanding of $108,500,000 on the Columbia 2024A/B Notes, which is expected to be repaid with a portion of the proceeds of the Columbia 2025-B (Taxable) Bonds.

For additional information relating to the indebtedness to be refunded and other purposes of issuance, see "PURPOSE OF ISSUANCE" in this Official Statement.

ENERGY NORTHWEST

Energy Northwest was organized in 1957 as the Washington Public Power Supply System. By resolution of its Executive Board adopted on June 2, 1999, the Washington Public Power Supply System officially changed its name to Energy Northwest. Energy Northwest now has 29 members, consisting of 24 public utility districts and the cities of Centralia, Port Angeles, Richland, Seattle and Tacoma, all located in the State of Washington. Public Utility District No. 1 of Cowlitz County joined Energy Northwest in April 2024. Energy Northwest has the authority, among other things, to acquire, construct and operate plants, works and facilities for the generation and transmission of electric power and energy and to issue bonds and other evidences of indebtedness to finance the same.

Energy Northwest owns and operates the Columbia Generating Station, a nuclear electric generating station with a current net design electric rating of 1,174 megawatts ("MW"). Energy Northwest also owns and operates a hydroelectric facility, the Packwood Lake Hydroelectric Project ("Packwood"), that generates 26 MW of electricity. Energy Northwest also owns and operates the Nine Canyon Wind Project, which consists of 63 turbines and is capable of generating approximately 96 MW of electricity. In addition, Energy Northwest owned and has financial responsibility for four other nuclear electric generating projects that have been terminated: Energy Northwest Nuclear Project No. 1 ("Project 1"), Energy Northwest Nuclear Project No. 3 ("Project 3") and Energy Northwest Nuclear Projects Nos. 4 and 5 ("Projects 4 and 5"). Project 1 and Project 3 were terminated in 1994, and Projects 4 and 5 were terminated in 1982. For discussions concerning the termination of Projects 1, 3, 4 and 5, see "ENERGY NORTHWEST—PROJECT 1," "—PROJECT 3," and "—PROJECTS 4 AND 5" in this Official Statement. Project 1, Project 3 and Columbia are individually referred to herein as a "Net Billed Project" or a "Project" and collectively referred to herein as the "Net Billed Projects." Each of Project 1, Project 3 and Columbia is financed and accounted for as a separate utility system. Projects 4 and 5 were financed and accounted for as a single utility system separate and apart from all other Energy Northwest projects. All of Energy Northwest's projects are located in the State of Washington. For additional information relating to Energy Northwest, see "ENERGY NORTHWEST" in this Official Statement.

The United States of America, Department of Energy ("DOE"), acting by and through the Administrator of the Bonneville Power Administration ("Bonneville"), has acquired the capability of the Net Billed Projects. As more fully discussed under "SECURITY FOR THE NET BILLED BONDS—NET BILLING AND RELATED AGREEMENTS," Bonneville is obligated to meet the costs of such capability pursuant to Net Billing Agreements (hereinafter defined) for the Net Billed Projects, with payments being made through a combination of credits against customer bills and cash payments from the Bonneville Fund (hereinafter defined). Bonneville's obligations to make such credits and cash payments under the Net Billing Agreements continue notwithstanding suspension or termination of any of the Net Billed Projects.

THE BONNEVILLE POWER ADMINISTRATION

The information under this heading has been derived from information provided to Energy Northwest by Bonneville. For detailed information with respect to Bonneville, see Appendix A—"THE BONNEVILLE POWER ADMINISTRATION" in this Official Statement.

Bonneville was created by Federal law in 1937 to market electric power from the Bonneville Dam and to construct facilities necessary to transmit such power. Today, Bonneville markets electric power from 31 federally-owned hydroelectric projects, most of which are located in the Columbia River Basin and all of which were constructed and are operated by the United States Army Corps of Engineers (the "Corps") or the United States Bureau of Reclamation (the "Bureau"), and from several non-federally-owned projects, including the Columbia Generating Station. Bonneville sells and/or exchanges power under contracts with approximately 135 utilities in the Pacific Northwest and Pacific Southwest and with several industrial customers. It also owns and operates a high voltage transmission system comprising more than 15,000 circuit miles of high voltage transmission lines 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 parts of western Wyoming, northern Nevada, northern Utah and northern California (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 15 million people. Electric power sold by Bonneville accounts for approximately 32% of the electric power generated in 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 administrations within the DOE. Bonneville is required by law to meet certain energy requirements in the Region and is authorized to acquire power resources, to implement conservation measures and to take other actions to enable it to carry out its purposes. Bonneville is also required by law to operate and maintain its transmission system and to provide transmission service to eligible customers and to undertake certain other programs, such as fish and wildlife protection, mitigation and enhancement.

THE SERIES 2025-A/B BONDS

The Project 1 2025-A Bonds are special revenue obligations of Energy Northwest issued pursuant to the Project 1 Electric Revenue Bond Resolution. The Project 1 2025-A Bonds are secured by a pledge of all receipts, income and revenues derived by Energy Northwest from the ownership of Project 1 on a parity with the Project 1 Electric Revenue Bonds, and will be secured on a parity with any additional bonds, notes or other obligations of Energy Northwest that are issued pursuant to the Project 1 Electric Revenue Bond Resolution or any Project 1 Separate Resolution described under "SECURITY FOR THE NET BILLED BONDS—ADDITIONAL INDEBTEDNESS."

The Columbia 2025-A/B Bonds are special revenue obligations of Energy Northwest issued pursuant to the Columbia Electric Revenue Bond Resolution. The Columbia 2025-A/B Bonds are secured by a pledge of all receipts, income and revenues derived by Energy Northwest from the ownership of the Columbia Generating Station on a parity with the Columbia Electric Revenue Bonds, and will be secured on a parity with any additional bonds, notes or other obligations of Energy Northwest that are issued pursuant to the Columbia Electric Revenue Bond Resolution or any Columbia Separate Resolution described under "SECURITY FOR THE NET BILLED BONDS—ADDITIONAL INDEBTEDNESS."

The Project 3 2025-A Bonds are special revenue obligations of Energy Northwest issued pursuant to the Project 3 Electric Revenue Bond Resolution. The Project 3 2025-A Bonds are secured by a pledge of all receipts, income and revenues derived by Energy Northwest from the ownership of Project 3 on a parity with the Project 3 Electric Revenue Bonds, and will be secured on a parity with any additional bonds, notes or other obligations of Energy Northwest that are issued pursuant to the Project 3 Electric Revenue Bond Resolution or any Project 3 Separate Resolution described under "SECURITY FOR THE NET BILLED BONDS—ADDITIONAL INDEBTEDNESS."

There are no restrictions on the issuance of debt under the Electric Revenue Bond Resolutions or pursuant to any of the above mentioned Separate Resolutions, so long as the Net Billing Agreements and the other Project agreements are in effect and no event of default is existing under the applicable Electric Revenue Bond Resolutions. See "SECURITY FOR THE NET BILLED BONDS—ADDITIONAL INDEBTEDNESS" in this Official Statement.

Energy Northwest has covenanted that it will not issue any Project 1 bonds or other debt with a lien on Project 1 revenues superior to the Project 1 Electric Revenue Bonds; any Columbia bonds or other debt with a lien on Columbia Generating Station revenues superior to the Columbia Electric Revenue Bonds; or any Project 3 bonds or other debt with a lien on Project 3 revenues superior to the Project 3 Electric Revenue Bonds.

The Project 1 2025-A Bonds are secured by amounts derived pursuant to the Project 1 Net Billing Agreements with and through Bonneville from net billing credits and from cash payments from the Bonneville Fund, as described herein. The Columbia 2025-A/B Bonds are secured by amounts derived pursuant to Net Billing Agreements related to the Columbia Generating Station with and through Bonneville from net billing credits and from cash payments from the Bonneville Fund, as described herein. The Project 3 2025-A Bonds are secured by amounts derived pursuant to the Project 3 Net Billing Agreements with and through Bonneville from net billing credits and from cash payments from the Bonneville Fund, as described herein. The receipts, income and revenues derived from a Project secure only the Series 2025-A/B Bonds and other Electric Revenue Bonds relating to that Project. Accordingly, the owners of the Series 2025-A/B Bonds issued for a particular Project will have no claim on the receipts, income and revenues securing any other Energy Northwest Project. For further information, see "SECURITY FOR THE NET BILLED BONDS" in this Official Statement.

For further information on the Net Billed Bonds outstanding as of March 31, 2025, see "ENERGY NORTHWEST—ENERGY NORTHWEST INDEBTEDNESS" in this Official Statement.

NET BILLING AGREEMENTS

Under the Net Billing Agreements, the Participants in each Net Billed Project have contracted to purchase the capability of that Net Billed Project and have agreed to provide Energy Northwest with funds necessary to meet the costs of that Net Billed Project. These costs include the amounts that Energy Northwest is obligated to pay in each contract year into the various funds provided for in the Project 1 Electric Revenue Bond Resolution for debt service and for all other purposes of Project 1; in the Columbia Electric Revenue Bond Resolution for debt service and for all other purposes of Columbia; and in the Project 3 Electric Revenue Bond Resolution for debt service and for all other purposes of Project 3. The Net Billing Agreements also effected a simultaneous assignment of the Project capability from the Participants to Bonneville and created an obligation of Bonneville to pay the Participants (from net billing credits provided by Bonneville and from cash payments from the Bonneville Fund, as described herein) for their respective shares of the costs of the Net Billed Projects. Thus, Bonneville is ultimately obligated to meet such costs.

Under the Net Billing Agreements, payments to Energy Northwest generally are required to be made directly by the Participants, not directly by Bonneville. Such payments by the Participants are to be made in accordance with each Participant's participation in the purchase of the capability of the Net Billed Project. Bonneville is required to pay for the capability of the Net Billed Project assigned by the Participants to it by crediting (or net billing) Bonneville's bills to Participants for power and other services purchased by Participants from Bonneville by the amount of the payment required to be made by the Participants to Energy Northwest. To the extent that the total amount of Bonneville's bills to each Participant (and consequently the amount of such credit available) over a contract year (July 1 to June 30) is less than the payment required to be made by the Participant to Energy Northwest, Bonneville is obligated to pay the deficiency in cash to the Participant from the Bonneville Fund. In the opinion of Bonneville's General Counsel, under Federal statutes Bonneville may make payments to the United States Treasury only from net proceeds; all cash payment obligations of Bonneville, including cash deficiency payments relating to Net Billed Bonds and other operating and maintenance expenses, have priority over payments by Bonneville to the United States Treasury. Net proceeds are gross cash receipts remaining in the Bonneville Fund after deducting all of the costs paid by Bonneville to operate and maintain the Federal System other than those used to make payments to the United States Treasury for: (1) the repayment of the Federal investment in certain transmission facilities and the power-generating facilities at federally-owned hydroelectric projects in the Pacific Northwest; (2) debt service on bonds issued by Bonneville and sold to the United States Treasury; (3) repayments of appropriated amounts to the Corps and the Bureau for certain costs allocated to power generation at federally-owned hydroelectric projects in the Pacific Northwest; and (4) costs allocated to irrigation projects as are required by law to be recovered from power sales.

Cash payments and the provision of credits by Bonneville and payments by Participants under each Net Billing Agreement are required whether or not the related Net Billed Project is completed, operable or operating and notwithstanding the suspension, interruption, interference, reduction or curtailment of Net Billed Project output or termination of the related Net Billed Project, and such payments or credits are not subject to any reduction, whether by offset or otherwise, and are not conditioned upon the performance or nonperformance by Energy Northwest, Bonneville or any Participant under the Net Billing Agreements or any other agreement or instrument.

Bonneville's obligations under the Net Billing Agreements are not general obligations of the United States of America and are not secured by the full faith and credit of the United States of America.

As described under "SECURITY FOR THE NET BILLED BONDS—NET BILLING AND RELATED AGREEMENTS—Direct Pay Agreements," in 2006 Energy Northwest and Bonneville entered into an agreement with respect to each Net Billed Project pursuant to which Bonneville pays at least monthly all costs for each Net Billed Project directly to Energy Northwest. One effect of the Direct Payment Agreements is that each Participant pays Bonneville directly all costs associated with the Participant's contracts with Bonneville. The Direct Pay Agreements do not amend the Net Billing Agreements. Although the payments to Energy Northwest under the Direct Pay Agreements are included under the respective pledge of revenues for the related series of Net Billed Bonds, such agreements are not pledged to secure the payment of the related series of Net Billed Bonds and are subject to termination and amendment solely upon mutual agreement of Bonneville and Energy Northwest.

For further information as to the Net Billing Agreements, see "SECURITY FOR THE NET BILLED BONDS—NET BILLING AND RELATED AGREEMENTS," "LEGAL MATTERS" and Appendix G—"SUMMARY OF CERTAIN PROVISIONS OF RELATED CONTRACTS" in this Official Statement. For information with respect to Bonneville, see Appendix A—"THE BONNEVILLE POWER ADMINISTRATION" in this Official Statement.

DESCRIPTION OF THE SERIES 2025-A/B BONDS

GENERAL

The Series 2025-A/B Bonds are dated the date of their delivery, and mature on July 1 in the years and in the principal amounts shown on the inside cover pages of this Official Statement. The Series 2025-A/B Bonds bear interest, payable on January 1 and July 1 of each year, commencing January 1, 2026, at the rates shown on the inside cover pages of this Official Statement. Interest on the Series 2025-A/B Bonds will be calculated based on a 360-day year consisting of twelve 30-day months. The Bank of New York Mellon Trust Company, N.A. has been appointed the Trustee, Paying Agent and Registrar for the Series 2025-A/B

Bonds (collectively, the "Trustee"). For so long as the Series 2025-A/B Bonds are registered in the name of Cede & Co. (as nominee of The Depository Trust Company, New York, New York ("DTC")) or its registered assigns, payments of principal and interest shall be made in accordance with the operational arrangements of DTC.

Book-Entry System; Transferability and Registration

The Series 2025-A/B Bonds are available to the ultimate purchasers in book-entry form only, in denominations of $5,000 and integral multiples thereof. Purchasers of the Series 2025-A/B Bonds will not receive certificates representing their interests in such Series 2025-A/B Bonds purchased, except as described in Appendix I—"BOOK-ENTRY SYSTEM" in this Official Statement. DTC will act as initial securities depository for each Series of Series 2025-A/B Bonds. As discussed in Appendix I—"BOOK-ENTRY SYSTEM," transfers of ownership interests in the Series 2025-A/B Bonds will be accomplished by book entries made by DTC and, in turn, by DTC Participants (as defined in Appendix I—"BOOK-ENTRY SYSTEM") acting on behalf of Beneficial Owners of the Series 2025-A/B Bonds. Energy Northwest, the Trustee and any other person may treat the registered owner of any Series 2025-A/B Bonds as the absolute owner of such Series 2025-A/B Bonds for the purpose of making payment thereof and for all other purposes, and Energy Northwest and the Trustee shall not be bound by any notice or knowledge to the contrary, whether such Series 2025-A/B Bonds shall be overdue or not. All payments of or on account of interest or principal to any registered owner of any such Series 2025-A/B Bonds shall be valid and effectual and shall be a discharge of Energy Northwest and the Trustee in respect of the liability upon such Series 2025-A/B Bonds, to the extent of the sum or sums paid.

When Series 2025-A/B Bonds are registered in the name of Cede & Co., as nominee of DTC, Energy Northwest and the Trustee shall have no responsibility or obligation to any DTC Participant or to any person on behalf of whom a DTC Participant holds an interest in the Series 2025-A/B Bonds with respect to (1) the accuracy of the records of DTC, Cede & Co. or any DTC Participant with respect to any ownership interest in the Series 2025-A/B Bonds, (2) the delivery to any DTC Participant or any other person, other than a registered owner as shown on the bond register, of any notice with respect to the Series 2025-A/B Bonds, including any notice of redemption, (3) the payment to any DTC Participant or any other person, other than a registered owner as shown on the bond register, of any amount with respect to principal of, premium, if any, or interest on the Series 2025-A/B Bonds, (4) the selection by DTC or any DTC Participant of any person to receive payment in the event of a partial redemption of the Series 2025-A/B Bonds, (5) any consent given or action taken by DTC as registered owner, or (6) any other matter. Energy Northwest and the Trustee may treat and consider Cede & Co., in whose name each Series 2025-A/B Bond is registered, as the holder and absolute owner of such Series 2025-A/B Bond for the purpose of payment, giving notices of redemption and other matters.

Discontinuation of Book-Entry Transfer System

If Energy Northwest determines to discontinue the book-entry system of transfer, Energy Northwest is required to execute, authenticate and deliver at no cost to the beneficial owners of the Series 2025-A/B Bonds, Series 2025-A/B Bonds in fully registered form, in the denomination of $5,000 or any integral multiple thereof. Thereafter, the principal of the Series 2025-A/B Bonds shall be payable upon due presentment and surrender thereof at the designated office of the Trustee, and interest on the Series 2025-A/B Bonds will be payable by check or draft mailed to the persons in whose names such Series 2025-A/B Bonds are registered, at the address appearing upon the registration books on the 15th day of the month next preceding an interest payment date; provided, however, that upon the written request of a registered owner of at least $1,000,000 in aggregate principal amount of a Series of the Series 2025-A/B Bonds outstanding, interest will be paid by wire transfer on the date due to an account with a bank located in the United States. If the book-entry transfer system for the Series 2025-A/B Bonds is discontinued, registered ownership of any Series 2025-A/B Bond may be transferred or exchanged by surrendering such Series 2025-A/B Bond to the Trustee, with the assignment form appearing on the Series 2025-A/B Bond duly executed. The Trustee shall not be required to transfer any Series 2025-A/B Bond during the 15 days preceding an interest payment or redemption date.

REDEMPTION

Optional Redemption

Series 2025-A Bonds. The Series 2025-A Bonds maturing on and after July 1, 2036, are subject to redemption at the option of Energy Northwest (with the approval of Bonneville) on or after July 1, 2035, in whole or in part (with maturities to be selected by Energy Northwest, with the approval of Bonneville), on any Business Day, at a Redemption Price equal to 100% of the principal amount of the Series 2025-A Bonds to be redeemed, plus interest accrued to the date of redemption.

Series 2025-B (Taxable) Bonds. The Series 2025-B (Taxable) Bonds are subject to redemption prior to their respective maturities at the option of Energy Northwest (with the approval of Bonneville), in whole or in part (with maturities to be selected by Energy Northwest, with the approval of Bonneville), on any Business Day, at the Make-Whole Redemption Price (as defined herein) determined by the Designated Investment Banker (as defined herein).

The "Make-Whole Redemption Price" is the greater of (1) the issue price as shown on the inside cover page of this Official Statement (but not less than 100% of the principal amount) of the Series 2025-B (Taxable) Bonds to be redeemed, or (2) the sum of the present values of the remaining scheduled payments of principal and interest on the Series 2025-B (Taxable) Bonds to be redeemed to the maturity date, not including any portion of those payments of interest accrued and unpaid as of the date on which the Series 2025-B (Taxable) Bonds are to be redeemed, discounted to the date on which such Series 2025-B (Taxable)

Bonds are to be redeemed on a semi-annual basis, assuming a 360-day year consisting of twelve 30-day months, at the "Treasury Rate" (defined below) plus 10 basis points, plus accrued and unpaid interest on the Series 2025-B (Taxable) Bonds to be redeemed on the redemption date.

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

"Treasury Rate" means, with respect to any redemption date for a particular Series 2025-B (Taxable) Bond, the rate per annum, expressed as a percentage of the principal amount, equal to the semi-annual equivalent yield to maturity or interpolated maturity of the Comparable Treasury Issue (defined below), assuming that the Comparable Treasury Issue is purchased on the redemption date for a price equal to the Comparable Treasury Price (defined below), as calculated by the Designated Investment Banker (defined below).

"Comparable Treasury Issue" means, with respect to any Valuation Date for a redemption date for a particular Series 2025-B (Taxable) Bond, the U.S. Treasury security or securities selected by the Designated Investment Banker that has an actual or interpolated maturity comparable to the remaining average life of the Series 2025-B (Taxable) Bonds to be redeemed, and that would be utilized in accordance with customary financial practice in pricing new issues of debt securities of comparable maturity to the remaining average life of such Series 2025-B (Taxable) Bonds to be redeemed.

"Comparable Treasury Price" means, with respect to any Valuation Date for a redemption date for a particular Series 2025-B (Taxable) Bond, (1) the most recent yield data for the applicable U.S. Treasury maturity index from the Federal Reserve Statistical Release H.15 Daily Update (or any comparable or successor publication) reported, as of 11:00 a.m. New York City time, on the Valuation Date; or (2) if the yield described in (1) above is not reported as of such time or the yield reported as of such time is not ascertainable, the average of five Reference Treasury Dealer Quotations for that redemption date, after excluding the highest and lowest such Reference Treasury Dealer Quotations, or if the Designated Investment Banker obtains fewer than five Reference Treasury Dealer Quotations, the average of all such quotations.

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

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

"Reference Treasury Dealer Quotations" means, with respect to each Reference Treasury Dealer and any redemption date for a particular Series 2025-B (Taxable) Bond, the average, as determined by the Designated Investment Banker, of the bid and asked prices for the Comparable Treasury Issue (expressed in each case as a percentage of its principal amount) quoted in writing to Energy Northwest, the Trustee and Bonneville by such Reference Treasury Dealer at 3:30 p.m. (New York City time) on the Valuation Date.

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

Partial Redemption

If less than all of the Series 2025-A Bonds are to be redeemed, Energy Northwest may select the Series and maturity or maturities, including any sinking fund redemptions of Term Bonds, to be redeemed. If less than all of the Series 2025-A Bonds of any Series or maturity are to be redeemed, the Series 2025-A Bonds or portions thereof to be redeemed are to be selected by the Trustee or DTC, as applicable, by lot. The Electric Revenue Bond Resolutions related to such bonds provide that the portion of any Series 2025-A/B Bonds of a denomination of more than $5,000 to be redeemed will be in the principal amount of $5,000 or any integral multiple thereof and that in selecting portions of such Series 2025-A/B Bonds for redemption, the Trustee will treat each such Series 2025-A/B Bond as representing that number of such Series 2025-A/B Bonds of $5,000 denomination that is obtained by dividing the principal amount of such Series 2025-A/B Bonds to be redeemed in part by $5,000.

If less than all of the Series 2025-B (Taxable) Bonds are to be redeemed, the particular maturities of Series 2025-B (Taxable) Bonds to be redeemed at the option of the Energy Northwest will be determined by Energy Northwest in its sole discretion.

If the Series 2025-B (Taxable) Bonds are registered in book-entry only form and so long as DTC or a successor securities depository is the sole registered owner of such Series 2025-B (Taxable) Bonds, if less than all of the Series 2025-B (Taxable) Bonds of a maturity are called for prior redemption, the particular Series 2025-B (Taxable) Bonds or portions thereof to be redeemed shall be allocated on a pro rata pass-through distribution of principal basis in accordance with DTC procedures, provided that, so long as the Series 2025-B (Taxable) Bonds are held in book-entry form, the selection for redemption of such Series 2025-B (Taxable) Bonds shall be made in accordance with the operational arrangements of DTC then in effect, and, if the DTC operational arrangements or the Electric Revenue Bond Resolutions do not allow for redemption on a pro rata pass-through distribution of principal basis, the Series 2025-B (Taxable) Bonds will be selected for redemption, in accordance with DTC procedures, by lot.

Energy Northwest intends that redemption allocations made by DTC be made on a pro rata pass-through distribution of principal basis as described above. However, neither Energy Northwest nor the Underwriters can provide any assurance that DTC, DTC's direct and indirect participants or any other intermediary will allocate the redemption of Series 2025-B (Taxable) Bonds on such basis.

Notice of Redemption

Notice of redemption of any Series 2025-A/B Bonds is to be given by the Trustee by first-class mail not less than 20 days nor more than 60 days before the redemption date to the registered owners of the Series 2025-A/B Bonds which are to be redeemed at their last addresses shown on the registration books for the Series 2025-A/B Bonds. Such notice shall be deemed conclusively to be received by the registered owners of the Series 2025-A/B Bonds which are to be redeemed, whether or not such notice is actually received. Mailing of such notice of redemption shall not be a condition precedent to such redemption, and failure to mail any such notice or any defect therein shall not affect the validity of the redemption proceedings for the Series 2025-A/B Bonds being redeemed. Notice of redemption having been given as described above, unless cancelled as described below, the Series 2025-A/B Bonds called for redemption shall become due and payable on the redemption date specified in such notice and interest thereon shall cease to accrue from and after the redemption date, if money sufficient for the redemption of the Series 2025-A/B Bonds to be redeemed, together with interest thereon to the redemption date, is held by the Trustee on the redemption date and the Series 2025-A/B Bonds (or such portions thereof) shall cease to be entitled to any benefit or security under the applicable resolutions. Energy Northwest may cancel notice of an optional redemption prior to the designated redemption date by giving written notice of such cancellation to all parties who were given notice of redemption in the same manner as such notice was given.

For so long as a book-entry system is in effect with respect to the Series 2025-A/B Bonds, the Trustee will mail notices of redemption to DTC or its nominee or its successor, and, if less than all of the Series 2025-A/B Bonds of a maturity are to be redeemed, DTC or its successor and DTC Participants and Indirect Participants (as such terms are defined in Appendix I—"BOOK-ENTRY SYSTEM") will determine the particular ownership interests of Series 2025-A/B Bonds to be redeemed. Any failure of DTC or its successor or a Participant or Indirect Participant to do so, or to notify a Beneficial Owner of a Series 2025-A/B Bond of any redemption, will not affect the sufficiency or the validity or the redemption of Series 2025-A/B Bonds.

Neither Energy Northwest, the Trustee, nor the Underwriters can give any assurance that DTC, the DTC Participants or the Indirect Participants will distribute such redemption notices to the Beneficial Owners of the Series 2025-A/B Bonds, or that they will do so on a timely basis.

Open Market Purchases

Energy Northwest has reserved the right to purchase any Series 2025-A/B Bonds on the open market at any time and at any price.

DEFEASANCE

The liens, pledges, charges, trusts, covenants and agreements of Energy Northwest made or provided for in the Project 1 Electric Revenue Bond Resolution, the Columbia Electric Revenue Bond Resolution or the Project 3 Electric Revenue Bond Resolution shall be fully discharged and satisfied as to any related Series 2025-A/B Bond, and such Series 2025-A/B Bond shall no longer be deemed to be outstanding under the Project 1 Electric Revenue Bond Resolution, Columbia Electric Revenue Bond Resolution or Project 3 Electric Revenue Bond Resolution, as applicable, when payment of principal of and premium, if any, on such Series 2025-A/B Bond, plus interest on such principal to the date thereof shall have been made or shall have been provided for by irrevocably depositing with the Trustee or a separate paying agent for such Series 2025-A/B Bond, in trust, and irrevocably appropriating and setting aside exclusively for such payment, either (1) money sufficient to make such payment, or (2) specified "defeasance obligations" maturing or redeemable at the option of the owner thereof, as to principal and interest in such amount and at such times as will assure the availability of sufficient money to make such payment, together with all necessary and proper fees, compensation and expenses of the Trustee and the paying agent pertaining to such Series 2025-A/B Bond. Defeasance obligations are defined in RCW 39.53 and include direct obligations of the United States and certain obligations of United States agencies and instrumentalities and others as defined under "Government Obligations" in Appendix H. See Appendix H—"SUMMARY OF CERTAIN PROVISIONS OF THE ELECTRIC REVENUE BOND RESOLUTIONS AND THE SUPPLEMENTAL ELECTRIC REVENUE BOND RESOLUTIONS—Defeasance (Article XI)" for a discussion of defeasance of the Series 2025-A/B Bonds.

If Energy Northwest defeases any Series 2025-B (Taxable) Bond, such Series 2025-B (Taxable) Bond may be deemed to be retired for federal income tax purposes as a result of the defeasance. In that event, the Beneficial Owner of the Series 2025-B (Taxable) Bond will recognize taxable gain or loss equal to the difference between the amount realized from the deemed sale, exchange or retirement (less any accrued qualified stated interest which will be taxable as such) and the Beneficial Owner's adjusted tax basis in the Series 2025-B (Taxable) Bond. See "TAX MATTERS—SERIES 2025-B (TAXABLE) BONDS."

PURPOSE OF ISSUANCE

The Project 1 2025-A Bonds are being issued for the purpose of currently refunding $283,790,000 aggregate principal amount of the Project 1 Electric Revenue Bonds, and paying the costs of issuing the Project 1 2025-A Bonds.

The Columbia 2025-A Bonds are being issued for the purpose of currently refunding $237,535,000 aggregate principal amount of the Columbia Electric Revenue Bonds, financing certain additions and improvements to the Columbia Generating Station and paying the costs of issuing the Columbia 2025-A Bonds. The Columbia 2025-B (Taxable) Bonds are being issued for the purpose of (directly or indirectly through repayment of the Columbia 2024A/B Notes as described below) paying fuel related costs and financing certain additions and improvements to the Columbia Generating Station and paying the costs of issuing the Columbia 2025-B (Taxable) Bonds and Columbia 2025-A Bonds.

Pursuant to the 2024 Loan Agreement, Energy Northwest borrowed $108,500,000 of the taxable portion to fund a portion of the costs of acquiring fuel for the Columbia Generating Station. Energy Northwest's obligation to repay the taxable advance under the 2024 Loan Agreement for this purpose is evidenced by the taxable portion of the Columbia 2024A/B Notes. The Columbia 2024A/B Notes are secured on a parity with the Columbia Electric Revenue Bonds issued by Energy Northwest under the Columbia Electric Revenue Bond Resolution and with all other obligations issued pursuant to additional related Columbia Separate Resolutions.

The Project 3 2025-A Bonds are being issued for the purpose of currently refunding $184,410,000 aggregate principal amount of the Project 3 Electric Revenue Bonds, and paying the costs of issuing the Project 3 2025-A Bonds.

A portion of the proceeds of the Project 1 Series 2025-A Bonds, Columbia 2025-A Bonds and Project 3 Series 2025-A Bonds will be used to refund or pay at maturity all of the following Electric Revenue Bonds:

Electric Revenue Bonds to be Currently Refunded:

Project	Series	Amount	Maturity (July 1)	Interest Rate	Payment or Redemption Date	Redemption Price	CUSIP No.
1	2015-A	$ 20,000,000	2027	5.000%	July 1, 2025	100%	29270CG66
1	2015-A	30,345,000	2028	5.000	July 1, 2025	100	29270CG58
1	2015-C	15,000,000	2025	3.000	N/A	N/A	29270CP58
1	2015-C	29,005,000	2025	5.000	N/A	N/A	29270CP66
1	2016-A	129,910,000	2025	5.000	N/A	N/A	29270CP90
1	2024-B	59,530,000	2025	5.000	N/A	N/A	29270C6A8
Columbia	2015-A	23,670,000	2029	5.000	July 1, 2025	100	29270CH32
Columbia	2015-A	10,000,000	2030	5.000	July 1, 2025	100	29270CJ55
Columbia	2015-A	10,000,000	2031	5.000	July 1, 2025	100	29270CJ63
Columbia	2015-A	27,400,000	2032	5.000	July 1, 2025	100	29270CJ48
Columbia	2015-A	28,765,000	2033	5.000	July 1, 2025	100	29270CH73
Columbia	2015-A	30,205,000	2034	5.000	July 1, 2025	100	29270CH81
Columbia	2015-A	15,000,000	2035	5.000	July 1, 2025	100	29270CH99
Columbia	2015-A	53,970,000	2038(1)	5.000	July 1, 2025	100	29270CJ89
Columbia	2015-C	18,795,000	2030	5.000	July 1, 2025	100	29270CP33
Columbia	2015-C	19,730,000	2031	5.000	July 1, 2025	100	29270CP41
3	2015-A	36,385,000	2025	5.000	N/A	N/A	29270CK46
3	2015-A	38,200,000	2026	5.000	July 1, 2025	100	29270CK38
3	2015-C	26,675,000	2026	5.000	July 1, 2025	100	29270CP74
3	2017-A	41,780,000	2025	5.000	N/A	N/A	29270CV85
3	2018-C	41,370,000	2025	5.000	N/A	N/A	29270C2B0

(1) Term bonds.

A portion of the proceeds of the Project 1 Series 2025-A Bonds, Columbia 2025-A Bonds and Project 3 Series 2025-A Bonds, together with other available amounts, and available funds of Energy Northwest, where applicable, will be deposited in a refunding account or the respective debt service accounts for each Series of Refunded Bonds to be refunded, which may be pursuant to an escrow agreement, and may be, at the direction of Energy Northwest, used to purchase certain investment securities permitted by the Electric Revenue Bond Resolutions. The amounts deposited in the refunding accounts, debt service accounts or used to purchase investment securities, together with the interest to accrue thereon, will be applied to pay the principal or redemption price, if any, and all or a portion of the interest on the Electric Revenue Bonds to be refunded as set forth in the table above. The Bond Fund Trustee for the Electric Revenue Bonds will give notice of redemption of such Electric Revenue Bonds to be redeemed when and as provided in the Electric Revenue Bond Resolutions.

The accuracy of (1) the arithmetical computations as to the adequacy of the principal of and interest on any investment securities, together with other available funds, to pay the principal or redemption price of the above-referenced Electric Revenue Bonds to be currently refunded to the date of their retirement and (2) the adjusted yields on the investments acquired with the proceeds of the Project 1 Series 2025-A Bonds, Columbia 2025-A Bonds and Project 3 Series 2025-A Bonds will be verified by BLX Group LLC.

SOURCES AND USES OF FUNDS[1]

SOURCES OF FUNDS

Project 1	
Principal of Project 1 2025-A Bonds	$ 258,890,000
Original Issue Premium	24,896,915
Total	$ 283,786,915
Columbia	
Principal of Columbia 2025-A Bonds	$ 404,135,000
Principal of Columbia 2025-B (Taxable) Bonds	109,025,000
Original Issue Premium	34,881,261
Total	$ 548,041,261
Project 3	
Principal of Project 3 2025-A Bonds	$ 173,185,000
Original Issue Premium	11,219,888
Total	$ 184,404,888

USES OF FUNDS

Project 1	
Deposit with trustee to currently refund Project 1 Electric Revenue Bonds	$ 282,413,218
Costs of issuing Project 1 2025-A Bonds (including Underwriters' compensation)	1,373,697
Total	$ 283,786,915
Columbia	
Deposit into Construction Account	$ 200,519,000
Deposit with trustee to currently refund Columbia Electric Revenue Bonds	236,382,620
Columbia 2024A/B Note Repayment	108,500,000
Costs of issuing Columbia 2025-A/B Bonds (including Underwriters' compensation)	2,639,641
Total	$ 548,041,261
Project 3	
Deposit with trustee to currently refund Project 3 Electric Revenue Bonds	$ 183,515,352
Costs of issuing Project 3 2025-A Bonds (including Underwriters' compensation)	889,536
Total	$ 184,404,888

(1) Totals may not add due to rounding.

SECURITY FOR THE NET BILLED BONDS

PLEDGE OF REVENUES AND PRIORITY

The Project 1 2025-A Bonds are special revenue obligations of Energy Northwest issued under and pursuant to the Project 1 Electric Revenue Bond Resolution and are secured by a pledge of the receipts, income and revenues derived by Energy Northwest from the ownership of Project 1. The Project 1 2025-A Bonds are a charge on the receipts, income and revenues of Project 1 subordinate to the payments to be made with respect to Energy Northwest's cost of operating and maintaining Project 1, and amounts required for the payment of taxes, assessments and other governmental charges or payments in lieu thereof. The Project 1 Electric Revenue Bonds, including the Project 1 2025-A Bonds, are also secured by a pledge of the proceeds of the sale of Project 1 Electric Revenue Bonds, pending application thereof in accordance with the provisions of the Project 1 Electric Revenue Bond Resolution, and the Debt Service Fund created pursuant to the Project 1 Electric Revenue Bond Resolution, including the investments, if any, therein. Under the Project 1 Electric Revenue Bond Resolution, the Project 1 2025-A Bonds will be secured on a parity with any bonds, notes or other obligations heretofore or hereafter issued by Energy Northwest under the Project 1 Electric Revenue Bond Resolution and other obligations of Energy Northwest issued pursuant to any Project 1 Separate Resolution. There were outstanding as of March 31, 2025, $801,805,000 principal amount of Project 1 Electric Revenue Bonds.

There are no Project 1 bonds outstanding that have a lien on Project 1 revenues that is prior to the lien of the Project 1 Electric Revenue Bonds.

The Columbia 2025-A/B Bonds are special revenue obligations of Energy Northwest issued under and pursuant to the Columbia Electric Revenue Bond Resolution and are secured by a pledge of the receipts, income and revenues derived by Energy Northwest from the ownership of Columbia. The Columbia 2025-A/B Bonds are a charge on the receipts, income and revenues of Columbia subordinate to the payments required to be made with respect to Energy Northwest's cost of operating and maintaining Columbia, and amounts required for the payment of taxes, assessments and other governmental charges or payments in lieu thereof. The Columbia Electric Revenue Bonds, including the Columbia 2025-A/B Bonds, are also secured by a pledge of the proceeds of the sale of Columbia Electric Revenue Bonds, pending application thereof in accordance with the provisions of the Columbia Electric Revenue Bond Resolution, and the Debt Service Fund created pursuant to the Columbia Electric Revenue Bond Resolution, including the investments, if any, therein. Under the Columbia Electric Revenue Bond Resolution, the Columbia 2025-A/B Bonds will be secured on a parity with any bonds, notes or other obligations heretofore or hereafter issued by Energy Northwest under the Columbia Electric Revenue Bond Resolution and other obligations of Energy Northwest issued pursuant to any Columbia Separate Resolution. There were outstanding as of March 31, 2025, $3,143,000,000 principal amount of Columbia Electric Revenue Bonds. There are no Columbia bonds outstanding that have a lien on Columbia Generating Station revenues that is prior to the lien of the Columbia Electric Revenue Bonds.

The Project 3 2025-A Bonds are special revenue obligations of Energy Northwest issued under and pursuant to the Project 3 Electric Revenue Bond Resolution and are secured by a pledge of the receipts, income and revenues derived by Energy Northwest from the ownership of Project 3. The Project 3 2025-A Bonds are a charge on the receipts, income and revenues of Project 3 subordinate to the payments to be made with respect to Energy Northwest's cost of operating and maintaining Project 3, and amounts required for the payment of taxes, assessments and other governmental charges or payments in lieu thereof. The Project 3 Electric Revenue Bonds, including the Project 3 2025-A Bonds, are also secured by a pledge of the proceeds of the sale of Project 3 Electric Revenue Bonds, pending application thereof in accordance with the provisions of the Project 3 Electric Revenue Bond Resolution, and the Debt Service Fund created pursuant to the Project 3 Electric Revenue Bond Resolution, including the investments, if any, therein. Under the Project 3 Electric Revenue Bond Resolution, the Project 3 2025-A Bonds will be secured on a parity with any bonds, notes or other obligations heretofore or hereafter issued by Energy Northwest under the Project 3 Electric Revenue Bond Resolution and other obligations of Energy Northwest issued pursuant to any Project 3 Separate Resolution. There were outstanding as of March 31, 2025, $937,700,000 principal amount of Project 3 Electric Revenue Bonds. There are no Project 3 bonds outstanding that have a lien on Project 3 revenues that is prior to the lien of the Project 3 Electric Revenue Bonds.

Energy Northwest has covenanted with the owners of the Project 1 Electric Revenue Bonds that it will not issue any bonds, warrants or other obligations that will have a pledge of and lien on the Project 1 revenues prior to the Project 1 Electric Revenue Bonds, has covenanted with the owners of the Columbia Electric Revenue Bonds that it will not issue any bonds, warrants or other obligations that will have a pledge of and lien on the Columbia Generating Station revenues prior to the Columbia Electric Revenue Bonds, and has covenanted with the owners of the Project 3 Electric Revenue Bonds that it will not issue any bonds, warrants or other obligations that will have a pledge of and lien on the Project 3 revenues prior to the Project 3 Electric Revenue Bonds.

Amounts paid to Energy Northwest pursuant to the Project 1 Net Billing Agreements entered into among Energy Northwest, Bonneville and the Project 1 Participants (which amounts are ultimately derived from net billing credits provided by Bonneville and from cash payments from the Bonneville Fund) are the primary source of payment for the Project 1 2025-A Bonds. Energy Northwest is obligated to pay to the Trustee for the Project 1 Electric Revenue Bonds into the related Debt Service Fund, out of amounts paid to Energy Northwest pursuant to the Project 1 Net Billing Agreements, amounts sufficient to pay when due the principal of and premium, if any, and interest on the Project 1 Electric Revenue Bonds, including the Project 1 2025-A Bonds. See "—NET BILLING AND RELATED AGREEMENTS."

Amounts paid to Energy Northwest pursuant to the Columbia Net Billing Agreements entered into among Energy Northwest, Bonneville and the Columbia Participants (which amounts are ultimately derived from net billing credits provided by Bonneville and from cash payments from the Bonneville Fund) are the primary source of payment for the Columbia 2025-A/B Bonds. Energy Northwest is obligated to pay to the Trustee for the Columbia Electric Revenue Bonds into the related Debt Service Fund, out of amounts paid to Energy Northwest pursuant to the Columbia Net Billing Agreements, amounts sufficient to pay when due the principal of and premium, if any, and interest on the Columbia Electric Revenue Bonds, including the Columbia 2025-A/B Bonds. See "—NET BILLING AND RELATED AGREEMENTS."

Amounts paid to Energy Northwest pursuant to the Project 3 Net Billing Agreements entered into among Energy Northwest, Bonneville and the Project 3 Participants (which amounts are ultimately derived from net billing credits provided by Bonneville and from cash payments from the Bonneville Fund) are the primary source of payment for the Project 3 2025-A Bonds. Energy Northwest is obligated to pay to the Trustee for the Project 3 Electric Revenue Bonds into the related Debt Service Fund, out of amounts paid to Energy Northwest pursuant to the Project 3 Net Billing Agreements, amounts sufficient to pay when due the principal of and premium, if any, and interest on the Project 3 Electric Revenue Bonds, including the Project 3 2025-A Bonds. See "—NET BILLING AND RELATED AGREEMENTS."

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

The Project 1 2025-A Bonds, the Columbia 2025-A/B Bonds and the Project 3 2025-A Bonds are separately secured and are not general obligations of Energy Northwest. The owners of the Project 1 2025-A Bonds will have no claim on the revenues or funds of any other Project of Energy Northwest, including those securing the Columbia 2025-A/B Bonds and the Project 3 2025-A Bonds. The owners of the Columbia 2025-A/B Bonds will have no claim on the revenues or funds of any other Project of Energy Northwest, including those securing the Project 1 2025-A Bonds and the Project 3 2025-A Bonds. The owners of the Project 3 2025-A Bonds will have no claim on the revenues or funds of any other Project of Energy Northwest, including those securing the Project 1 2025-A Bonds and the Columbia 2025-A/B Bonds. No Bondholder has a claim on the assets of any Project.

The Series 2025-A/B Bonds do not constitute an obligation of the State of Washington or of any political subdivision thereof, other than Energy Northwest. Energy Northwest has no taxing power.

See Appendix H—"SUMMARY OF CERTAIN PROVISIONS OF THE ELECTRIC REVENUE BOND RESOLUTIONS AND THE SUPPLEMENTAL ELECTRIC REVENUE BOND RESOLUTIONS."

EVENTS OF DEFAULT AND REMEDIES

For a description of the events of default and remedies applicable to the Electric Revenue Bonds, including the Series 2025-A/B Bonds, see Appendix H—"SUMMARY OF CERTAIN PROVISIONS OF THE ELECTRIC REVENUE BOND RESOLUTIONS AND THE SUPPLEMENTAL ELECTRIC REVENUE BOND RESOLUTIONS—Events of Default and Remedies (Section 801)."

If the maturity of Electric Revenue Bonds, including the Series 2025-A/B Bonds, were accelerated by the applicable Bond Fund Trustee or Trustee or the holders of the requisite principal amount of such bonds after an Event of Default under the respective Electric Revenue Bond Resolution, no assurance can be given that the principal amount of the accelerated Electric Revenue Bonds would be payable currently as a cost under the terms of the Net Billing Agreements related to such Net Billed Project. See "—NET BILLING AND RELATED AGREEMENTS—Payment Procedures" and "—LIMITATIONS ON REMEDIES" for a discussion of the limitations of certain remedies.

If there is an acceleration of a maturity of the Electric Revenue Bonds, Bonneville has taken the position since at least 1989 that Bonneville's and the Participants' obligations to make payments under the Net Billing Agreements would remain as though no such acceleration had occurred.

Payments and the provision of credits by Bonneville and payments by Participants under the Net Billing Agreements relating to the Net Billed Projects that are required to be made to Energy Northwest to pay the principal of and interest on the outstanding Net Billed Bonds issued for the related Net Billed Project are required to be made notwithstanding the occurrence of an Event of Default.

LIMITATIONS ON REMEDIES

Upon the occurrence of an Event of Default under the Electric Revenue Bond Resolutions, payment of the principal of and interest on the Series 2025-A/B Bonds may be accelerated. Any action to compel payment for money damages or to accelerate payment would be subject to the limitations on legal claims and remedies against public bodies under Washington law. The right to accelerate payments by a Washington municipality has not been tested by any Washington court. Any remedies available to Bondholders are in many respects dependent upon judicial actions, which are in turn often subject to discretion and delay and can be expensive and time-consuming to obtain. If Energy Northwest fails to comply with its covenants under the Electric Revenue Bond Resolutions or to pay principal of or interest on the Series 2025-A/B Bonds, there can be no assurance that available remedies will be adequate to fully protect the interest of the owners of the Series 2025-A/B Bonds. See "—EVENTS OF DEFAULT AND REMEDIES" for a discussion of possible limits of amounts payable under the Net Billing Agreements in the event of acceleration of the Net Billed Bonds.

In addition to the limitations on remedies in the Electric Revenue Bond Resolutions, the rights and obligations under the Series 2025-A/B Bonds may be limited by and are subject to bankruptcy, insolvency, reorganization, moratorium and other laws relating to or affecting creditors' rights, to the application of equitable principles, and to the exercise of judicial discretion in appropriate cases. The opinions to be delivered by Foster Garvey P.C., as Bond Counsel, concurrently with the issuance of the Series 2025-A/B Bonds will be subject to such limitations. See Appendix D-1—"PROPOSED FORM OF OPINIONS OF BOND COUNSEL FOR THE SERIES 2025-A/B BONDS," and Appendix D-2—"PROPOSED FORM OF SUPPLEMENTAL OPINIONS OF BOND COUNSEL FOR THE SERIES 2025-A/B BONDS."

NO RESERVE ACCOUNT

There is no reserve account securing repayment of the Series 2025-A/B Bonds. In the Electric Revenue Bond Resolutions, Energy Northwest has reserved the right to create a reserve account to secure a separate series of Electric Revenue Bonds.

ADDITIONAL INDEBTEDNESS

In each Electric Revenue Bond Resolution, Energy Northwest has reserved the right to issue, upon satisfaction of certain conditions set forth therein, additional bonds or notes under the Electric Revenue Bond Resolutions or under one or more separate resolutions ("Separate Resolutions") of the Executive Board creating a pledge of and lien on the receipts, income and revenues derived from the related Project of equal rank with the pledge and lien created by such Electric Revenue Bond Resolution in favor of the Electric Revenue Bonds. The Columbia 2024A/B Notes were issued pursuant to a related Separate Resolution. See "INTRODUCTION." There are no restrictions on or conditions to issuing debt on a parity with the Electric Revenue Bonds under the Electric Revenue Bond Resolutions, including the Series 2025-A/B Bonds, pursuant to Separate Resolutions, other than that the Net Billing Agreements and other Project agreements must be in effect and no event of default may exist under the applicable Electric Revenue Bond Resolution. There are no Project 1, Columbia or Project 3 prior lien bonds.

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

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

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

NET BILLING AND RELATED AGREEMENTS

General

Energy Northwest sold the entire capability of Project 1 to 104 publicly-owned utilities and rural electric cooperatives (the "Project 1 Participants") under net billing agreements (as amended, the "Project 1 Net Billing Agreements"). Energy Northwest sold the entire capability of the Columbia Generating Station to 94 publicly-owned utilities and rural electric cooperatives (the "Columbia Participants") under net billing agreements (as amended, the "Columbia Net Billing Agreements"). Energy Northwest sold the entire capability of its ownership share of Project 3 to 103 publicly-owned utilities and rural electric cooperatives (the "Project 3 Participants," and collectively with the Project 1 Participants and the Columbia Participants, the "Participants") under net billing agreements (as amended, the "Project 3 Net Billing Agreements," which, together with the Project 1 Net Billing Agreements and the Columbia Net Billing Agreements, are collectively referred to as the "Net Billing Agreements"). Under the Net Billing Agreements, each Participant assigned its share of the capability of the Net Billed Project to Bonneville. Each of the Participants is a customer of Bonneville. Many of the Participants are Participants in more than one Net Billed Project. See Appendix F—"ENERGY NORTHWEST PARTICIPANT UTILITY SHARE OF FISCAL YEAR 2025 BUDGETS" for a list of Participants and their respective shares of the Projects' fiscal year 2025 budgets.

Under the Net Billing Agreements, in payment for the share of the capability of each Net Billed Project purchased by each Participant, such Participant is obligated to pay Energy Northwest an amount equal to its share of Energy Northwest's costs for such Net Billed Project, less amounts payable from sources other than the related Net Billing Agreements, all as shown on the Participant's Billing Statement referred to below under "Payment Procedures." Bonneville is obligated to pay this amount to such Participant by providing net billing credits against the amounts such Participant owes Bonneville under the Participant's power sales and other contracts with Bonneville and by making the cash payments described below (subject to the limitations described herein under Appendix A—"THE BONNEVILLE POWER ADMINISTRATION—BONNEVILLE FINANCIAL OPERATIONS—The Bonneville Fund"). Each Participant is obligated to pay Energy Northwest an amount equal to the amount of such credits and cash payments as payment on account of its obligations to pay for its share of the Net Billed Project capability.

The Net Billing Agreements provide for cash payments and the provision of credits by Bonneville and payments by Participants whether or not the related Net Billed Project is completed, operable or operating and notwithstanding the suspension, interruption, interference, reduction or curtailment of the Net Billed Project output or termination of the related Net Billed Project, and such payments or credits are not subject to any reduction, whether by offset or otherwise, and are not conditioned upon the performance or nonperformance by Energy Northwest, Bonneville or any Participant under the Net Billing Agreements or any other agreement or instrument.

The Net Billing Agreements require each Participant to pay Energy Northwest the amount set forth in its Billing Statement or accounting statement. Each Participant is required to make payments to Energy Northwest only from revenues derived by the Participant from the ownership and operation of its electric utility properties and from payments made by Bonneville under the Net Billing Agreements. Each Participant has covenanted that it will establish, maintain and collect rates or charges for power and energy and other services furnished through its electric utility properties which shall be adequate to provide revenues sufficient to make required payments to Energy Northwest under the Net Billing Agreements and to pay all other charges and obligations payable from or constituting a charge and lien upon such revenues.

The authority of all of the Participants to enter into the Net Billing Agreements was affirmed in 1985 by the United States Court of Appeals for the Ninth Circuit in *City of Springfield v. Washington Public Power Supply System, et al.* (the "Springfield Case"). The United States Supreme Court denied a petition for a writ of certiorari. In upholding the Net Billing Agreements, the court in the Springfield Case found that the Net Billing Agreements are contracts for the purchase of electricity because the Net Billing Agreements place the dry hole risk on Bonneville and not on the Participants and because the Participants will receive either electricity or a cash refund equal to their payments to Energy Northwest. For a discussion of Bond Counsel's opinion with respect to the enforceability of the Net Billing Agreements, see "LEGAL MATTERS." For a summary of certain provisions of the Net Billing Agreements, see Appendix G—"SUMMARY OF CERTAIN PROVISIONS OF RELATED CONTRACTS."

Pending the receipt of the ruling in the Springfield Case, Energy Northwest and Bonneville entered into certain Assignment Agreements for each of Project 1, Columbia and Project 3 (the "Assignment Agreements"). For additional information with respect to the Assignment Agreements, see "—Assignment Agreements" and Appendix G—"SUMMARY OF CERTAIN PROVISIONS OF RELATED CONTRACTS."

By letter dated August 1, 1989 (the "1989 Letter Agreement"), Bonneville agreed with Energy Northwest that, in the event any Participant shall be unable for any reason, or shall fail or refuse, to pay to Energy Northwest any amount due from such Participant under its Net Billing Agreement for which a net billing credit or cash payment to such Participant has been provided by Bonneville, Bonneville will be obligated to pay the unpaid amount in cash directly to Energy Northwest, unless payment of such unpaid amount is made in a timely manner pursuant to the Net Billing Agreements.

As described under "Direct Pay Agreements," Energy Northwest and Bonneville executed an agreement with respect to each Net Billed Project pursuant to which Bonneville agrees to monthly pay all costs for each Net Billed Project directly to Energy Northwest and each Participant pays Bonneville directly all costs associated with the Participant's contracts with Bonneville. Although the payments to Energy Northwest under the Direct Pay Agreements are included under the respective pledge of revenues for the related series of Net Billed Bonds, such agreements are not pledged to secure the payment of the related series of Net Billed Bonds and are subject to termination and amendment solely upon mutual agreement of Bonneville and Energy Northwest.

All payments required to be made by Bonneville under the Net Billing Agreements, the Assignment Agreements, the 1989 Letter Agreement and the Direct Pay Agreements are to be made from the Bonneville Fund or other funds legally available therefor. See "—THE BONNEVILLE FUND" below.

Bonneville's obligations under the Net Billing Agreements are not general obligations of the United States of America and are not secured by the full faith and credit of the United States of America.

Payment Procedures

The Columbia Net Billing Agreements provide for the adoption by Energy Northwest of an Annual Budget, which, as amended from time to time, shall make provision for all Columbia costs, including, but not limited to, the amounts which Energy Northwest is required to pay in each contract year (July 1 to June 30) into the various funds provided for in the Columbia Electric Revenue Bond Resolution for debt service and all other purposes. The Annual Budget also includes the source of funds proposed to be used. The Annual Budget is submitted to Bonneville and to the Participants' Review Board established under the Columbia Net Billing Agreements and becomes effective 30 days after submitted unless it is disapproved by Bonneville or unless a recommendation or modification proposed by the Participants' Review Board is not accepted by Energy Northwest. In the event of a dispute, the matter is referred to a Project Consultant as described in Appendix G—"SUMMARY OF CERTAIN PROVISIONS OF RELATED CONTRACTS—The Project Agreements." Energy Northwest prepares a Billing Statement for that contract year for each Columbia Participant. The Billing Statement shows such Participant's share of the Annual Budget for Columbia less amounts payable from sources other than the Columbia Net Billing Agreements. The Annual Budget and Billing Statements may be amended during a contract year, if necessary. As described below, each Participant makes monthly payments to Energy Northwest in satisfaction of the amounts due under its Billing Statement.

In the month preceding the beginning of each contract year and in each month thereafter, Bonneville renders a bill to each Participant for power and other services under the Participant's power sales and other contracts with Bonneville. In the first month of the contract year, that bill shows an offsetting credit equal to the full amount of such bill to the extent of the Participant's share of the costs of Columbia. Within 30 days of receiving the monthly bill from Bonneville reflecting such credit, the Participant must pay Energy Northwest an amount equal to the credit for Columbia received from Bonneville. In each month thereafter during the contract year, such crediting by Bonneville and such payments to Energy Northwest by such Participant continue until the credits received by such Participant equal the total amount shown on such Participant's Billing Statement. The effect of this payment procedure is that amounts due Bonneville from the Participants (up to the Participants' obligations to Energy Northwest as shown on their Billing Statements) are required to be paid by the Participants to Energy Northwest rather than to Bonneville.

Project 1 and Project 3 have been terminated and, in accordance with the Net Billing Agreements for such Projects, the related Net Billing Agreements terminated except for those provisions that provide for the billing and payment of the costs of such Net Billed Project, including all amounts which Energy Northwest is required under the related Electric Revenue Bond Resolution to pay each year into the various funds for debt service and all other purposes, and the crediting of the proceeds of the disposition of the assets of such terminated Net Billed Project in reduction of such costs. The costs for each Net Billed Project after termination include all of Energy Northwest's accrued costs and liabilities resulting from Energy Northwest's ownership, construction, operation (including cost of fuel) and maintenance of and renewals and replacements to the terminated Project and all other Energy Northwest costs resulting from its ownership of such Project and the salvage, discontinuance, decommissioning and disposition or sale thereof and all amounts which Energy Northwest is required under the related Electric Revenue Bond Resolution to pay in each year into the various funds for debt service and all other purposes. The Columbia Net Billing Agreements have the same termination provision.

Since Project 1 and Project 3 have been terminated, Energy Northwest is required under each of the Project 1 Net Billing Agreements and Project 3 Net Billing Agreements to provide monthly accounting statements to Bonneville and to each Project 1 Participant and Project 3 Participant of all costs associated with such termination. The monthly accounting statements are required to credit against such costs all amounts received by Energy Northwest from the disposition of assets of Project 1 and Project 3. The Project 1 Net Billing Agreements provide that such monthly accounting statements shall continue until all Project 1 Net Billed Bonds have been paid or funds are set aside for their payment or the final disposition of Project 1, whichever is later. The Project 3 Net Billing Agreements provide that such monthly accounting statements shall continue until all Project 3 Net Billed Bonds have been paid or funds are set aside for their payment or the final disposition of Project 3, whichever is later. If the monthly accounting statements show that such costs exceed such credits, each Project 1 Participant and Project 3 Participant, as the case may be, is required to pay its portion of such excess costs to Energy Northwest. The payments are to be made at times and in amounts sufficient to discharge on a current basis the Project 1 Participant's share or Project 3 Participant's share, as the case may be, of the amount which Energy Northwest is required to pay into the various funds provided in the related Electric Revenue Bond Resolution for debt service and all other purposes.

In the event of a termination of the Columbia Generating Station, Energy Northwest is required under the Columbia Net Billing Agreements to provide monthly accounting statements to Bonneville and to each Columbia Participant of all costs associated with such termination in the manner discussed above for Project 1 and Project 3.

Post Termination Agreements

Bonneville and Energy Northwest have entered into Post Termination Agreements with respect to Projects 1 and 3, each dated June 14, 1994 (the "Post Termination Agreements"), which, among other things, facilitate the administration, budgeting and billing procedures with respect to such Projects. Nothing in the Post Termination Agreements impairs or prevents Energy Northwest from including in the monthly accounting statements with respect to each such Project all costs and obligations of Energy Northwest as discussed above.

Assignment of Participant Shares

If Bonneville determines that a Participant's payment obligations to Bonneville under its power sales and other contracts will not equal or exceed the Participant's payment obligations during a contract year under its Net Billing Agreement and, in the opinion of Bonneville and the Participant, such deficiency is expected to continue for a significant period, Bonneville is required under the related Net Billing Agreement to use its best efforts to assign such Participant's share of capability in the Net Billed Project (and the associated benefits and obligations) to other Participants in the Net Billed Project or to other Bonneville customers to the extent necessary to eliminate such Participant's net billing deficiency. The Net Billed Project capability so assigned would then be included by Bonneville under net billing arrangements with such other Participant or customer.

If Bonneville were unable to arrange for such assignments, the Participant would be required to make such assignment to other Participants pro rata. The other Participants would be obligated to accept such assignments to the extent required to eliminate such deficiency. Such mandatory assignments to any Participant may not exceed 25% of that Participant's original share of the Net Billed Project capability without the consent of that Participant. In addition, no such mandatory assignment may be made if it would cause the estimate of that Participant's obligation to Energy Northwest to exceed the estimate of the credits available to it from Bonneville, as estimated by Bonneville. Bonneville has made voluntary payments directly to Energy Northwest on behalf of Participants prior to reassigning their shares to eliminate net billing deficiencies. See "Voluntary Payments by Bonneville to Energy Northwest on Behalf of Participants."

The Net Billing Agreements provide that if reassignments cannot be made in amounts sufficient to bring into balance the respective dollar obligations of Bonneville and a Participant and an accumulated balance in favor of such Participant from a previous contract year is expected by Bonneville to be carried for an additional contract year, Bonneville is obligated to pay the balance. Any subsequent monthly net balances that exceed the amount of Bonneville's bill for that month will be paid to such

Participant by Bonneville as cash deficiency payments, subject to the limitations described herein under Appendix A—"THE BONNEVILLE POWER ADMINISTRATION—BONNEVILLE FINANCIAL OPERATIONS—The Bonneville Fund." The Participants are obligated to pay to Energy Northwest the amounts received from Bonneville within 30 days.

Voluntary Payments by Bonneville to Energy Northwest on Behalf of Participants

In 1979 and 1980, Bonneville and Energy Northwest entered into agreements with a large portion of the Participants (representing between roughly 70-80% of the capability of each Project, depending on the Project) relating to payments to Energy Northwest under the Net Billing Agreements. These agreements ("Voluntary Payment Agreements") provide that Bonneville, prior to making a reassignment of a Participant's share, may (but is not required to) pay directly to Energy Northwest, for the account of the Participant, the amount by which the Participant's obligation to Energy Northwest exceeds the billing credits allowed or estimated to be allowed to the Participant during the contract year. Under the Voluntary Payment Agreements, the related Participants agreed that they would not seek payment from Bonneville for any amounts so paid to Energy Northwest. In the case of Participants that have not signed Voluntary Payment Agreements, Bonneville has nonetheless made a number of similar voluntary payments to Energy Northwest on their behalf. When Bonneville does so it notifies the related Participants by letter that it has made such voluntary payments to Energy Northwest. See Appendix A—"THE BONNEVILLE POWER ADMINISTRATION—BONNEVILLE FINANCIAL OPERATIONS—Order in Which Bonneville's Costs Are Met" for more information. Because of these payments, no reassignments of Participants' shares or deficiency payments by Bonneville to Participants have been necessary. These payments have also assisted in managing the cash flow requirements of Energy Northwest.

Assignment Agreements

Pursuant to the Assignment Agreements, Energy Northwest assigned to Bonneville any rights to the capability of any of the Net Billed Projects that Energy Northwest may obtain as a result of a reversion of a Participant's share of such capability to Energy Northwest or by any other means. For example, in the event that it were judicially determined that any Participant is not obligated pursuant to the Net Billing Agreements to pay for any interest in Project capability which Bonneville obtains pursuant to the Assignment Agreements, Bonneville agreed to pay directly to Energy Northwest the amounts that would have been payable by the Participant under the Net Billing Agreements for such Project capability. For a summary of certain provisions of the Assignment Agreements, see Appendix G—"SUMMARY OF CERTAIN PROVISIONS OF RELATED CONTRACTS."

Direct Pay Agreements

Energy Northwest and Bonneville entered into an agreement with respect to each Net Billed Project ("Direct Pay Agreements") pursuant to which, beginning May 2006, Bonneville pays at least monthly all costs for each Net Billed Project, including debt service on the Net Billed Bonds, directly to Energy Northwest. Each Participant pays directly to Bonneville all costs associated with its power sales and other contracts with Bonneville instead of making such payments to Energy Northwest. The Net Billing Agreements provide that Energy Northwest is to bill budgeted costs less amounts payable from sources other than the Net Billing Agreements to Participants. Direct payments received from Bonneville under the Direct Pay Agreements are considered a source other than the Net Billing Agreements and, therefore, the Net Billing Agreements were not amended. In the Direct Pay Agreements, Energy Northwest agrees to promptly bill each Participant its share of the costs of the respective Project under the Net Billing Agreements if Bonneville fails to make a payment when due under the Direct Pay Agreements. Although the amounts received by Energy Northwest under the Direct Pay Agreements are included under the respective pledge of revenues for the related series of Net Billed Bonds, such agreements are not pledged to secure the payment of the related series of Net Billed Bonds and are subject to termination and amendment solely upon mutual agreement of Bonneville and Energy Northwest. If the Direct Pay Agreements were terminated, Bonneville and Energy Northwest would return to the payment procedures described under "—Payment Procedures" above. See "—PLEDGE OF REVENUES AND PRIORITY" and Appendix A—"THE BONNEVILLE POWER ADMINISTRATION—BONNEVILLE FINANCIAL OPERATIONS—Order in Which Bonneville's Costs Are Met."

Other Net Billing Obligations

In addition to the net billing obligations in connection with the Net Billed Projects, Bonneville has net billing obligations to certain Participants in connection with that portion of the project capability associated with the 30% share of the terminated Trojan Nuclear Project owned by the City of Eugene, Oregon, acting by and through the Eugene Water and Electric Board. The credits and payments received by each Participant from Bonneville in each month under all of that Participant's agreements providing for net billing are required by the Net Billing Agreements to be allocated pro rata among all of the Participants' net billing obligations.

Bonneville is authorized to enter into additional contracts providing for net billing or similar credits. The Net Billing Agreements provide that Bonneville and each Participant shall not enter into any agreement providing for net billing if Bonneville estimates that, as a result of such agreement, the aggregate of its billings to such Participant will be less than 115% of Bonneville's net billing obligations to such Participant under all agreements between Bonneville and such Participant providing for net billing. Bonneville has no present plans to enter into new agreements with Participants requiring net billing to fund resource acquisitions; however, in fiscal year (October 1 through September 30) ("Bonneville Fiscal Year") 2013, Bonneville and four Preference Customers (each of which is a Net Billing Participant) agreed to separate electricity prepayment arrangements in which the Preference Customers provided lump-sum payments to Bonneville as prepayments of a portion of their power purchases through September 30, 2028. The participating customers are entitled to future deliveries of a portion of the electricity pursuant to such

Long-Term Preference Contracts without additional payments. The right to future deliveries of that portion of electricity without additional payments is and will be reflected as fixed equal monthly credits to the participating customers' power bills from Bonneville. The prepayments are not for fixed blocks of electricity. The prepayments entitle the participating customers to receive a fixed monthly value of electricity, valued at Bonneville's then-applicable power rates. Bonneville received $340,000,000 in aggregate of prepayments from the participating customers. The offsetting prepayment credits are set at $2,550,000 per month, in aggregate, for power provided to the participating customers in the period April 1, 2013 through September 30, 2028. While Bonneville has no current plans to do so, it is possible that Bonneville may seek to use this form of Non-Federal Debt to meet some of its capital funding needs.

THE BONNEVILLE FUND

The Bonneville Fund is a continuing appropriation available exclusively to Bonneville for the purpose of making cash payments to cover Bonneville's expenses, including its cash payments to provide for that amount, if any, due under the Net Billing Agreements which is not paid from net billing credits. All receipts, collections and recoveries of Bonneville in cash from all sources are deposited in the Bonneville Fund. For a more complete discussion of the Bonneville Fund, see Appendix A—"THE BONNEVILLE POWER ADMINISTRATION—BONNEVILLE FINANCIAL OPERATIONS—The Bonneville Fund."

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

Net billing credits reduce Bonneville's cash receipts by the amount of the credits. Thus, costs of the Net Billed Projects, to the extent covered by net billing credits, can be met without regard to amounts in the Bonneville Fund.

Bonneville is required to make certain annual payments to the United States Treasury. These payments are subject to the availability of net proceeds, which are gross cash receipts remaining in the Bonneville Fund after deducting all of the costs paid by Bonneville to operate and maintain the Federal System (as defined in Appendix A—"THE BONNEVILLE POWER ADMINISTRATION"), other than those used to make payments to the United States Treasury for: (1) the repayment of the Federal investment in certain transmission facilities and the power generating facilities at federally-owned hydroelectric projects in the Pacific Northwest; (2) debt service on bonds issued by Bonneville and sold to the United States Treasury; (3) repayments of amounts appropriated to the Corps and the Bureau for costs allocated to power generation at federally-owned hydroelectric projects in the Pacific Northwest; and (4) costs allocated to irrigation projects as are required by law to be recovered from power sales.

For various reasons, Bonneville's revenues from the sale of electric power and other services may vary significantly from year to year. In order to accommodate such fluctuations in revenues and to assure that Bonneville has sufficient revenues to pay the costs necessary to maintain and operate the Federal System, all cash payment obligations of Bonneville other than to the United States Treasury, including cash deficiency payments relating to Net Billed Bonds and other operating and maintenance expenses, have priority over payments by Bonneville to the United States Treasury. In the opinion of Bonneville's General Counsel, under Federal statutes, Bonneville may make payments to the United States Treasury only from net proceeds; all other cash payments of Bonneville, including cash deficiency payments relating to Net Billed Bonds and other operating and maintenance expenses, have priority over payments by Bonneville to the United States Treasury for the costs described in (1) through (4) in the preceding paragraph.

The requirement to pay the United States Treasury exclusively from net proceeds would result in a deferral of United States Treasury payments if net proceeds were not sufficient for Bonneville to make its payments in full to the United States Treasury. Such deferrals could occur in the event that Bonneville were to receive less revenue or if Bonneville's costs were higher than expected. Such deferred amounts, plus interest, must be paid by Bonneville in future years. Bonneville has made all payments to the United States Treasury in full and on time since 1984, including in Bonneville Fiscal Year 2024.

Because Bonneville's payments to the United States Treasury may be made only from net proceeds, payments of other Bonneville costs out of the Bonneville Fund have a priority over its payments to the United States Treasury. Thus, the order in which Bonneville's costs are met is as follows: (1) Net Billed Project costs and Trojan Nuclear Project costs to the extent covered by net billing credits, (2) cash payments out of the Bonneville Fund to cover all required payments incurred by Bonneville pursuant to law, including net billing cash payments and payments under the Direct Pay Agreements, and other operating and maintenance expenses, including the costs of transmission facility lease-purchase agreements and electric power conservation or generating resource acquisitions, but excluding payments to the United States Treasury, and (3) payments to the United States Treasury. The costs of the Net Billed Projects are currently covered through the Direct Pay Agreements rather than by net billing credits.

For further information, see Appendix A—"THE BONNEVILLE POWER ADMINISTRATION—BONNEVILLE FINANCIAL OPERATIONS—Order in Which Bonneville's Costs Are Met" and "—Bonneville's Non-Federal Debt." For a discussion of certain direct payments by Bonneville for Federal System operations and maintenance, which payments would reduce the amount of deferrable appropriations obligations Bonneville would otherwise be responsible to repay, see Appendix A—"THE BONNEVILLE POWER ADMINISTRATION—BONNEVILLE FINANCIAL OPERATIONS—Direct Funding of Federal System Operations and Maintenance Expense."

Bonneville's obligation under the Net Billing Agreements for each Net Billed Project is to pay an amount equal to the costs of such Net Billed Project less any other funds which are required to be specified in the Annual Budget as payable from sources other than the payments to be made under such Net Billing Agreements. In the opinion of Bonneville's General Counsel, this provision would permit Bonneville to make payments on account of debt service on all Net Billed Bonds for a Net Billed Project directly to the applicable Bond Fund Trustee or Trustee. Such payment would be made only pursuant to an agreement with the applicable Bond Fund Trustee or Trustee requiring Bonneville to make such payment directly to the applicable Bond Fund Trustee or Trustee on or before the date such amounts would be required to be paid by Energy Northwest to the applicable Bond Fund Trustee or Trustee under the applicable Net Billed Resolution. Bonneville has no present intention of undertaking such actions. The effect of such an agreement would be to reduce the amount of costs included in the Annual Budget for the Net Billed Project to be paid under the Net Billing Agreements by the amount of the debt service payable directly by Bonneville to the applicable Bond Fund Trustee or Trustee.

For further information see Appendix A—"THE BONNEVILLE POWER ADMINISTRATION—BONNEVILLE FINANCIAL OPERATIONS."

ENERGY NORTHWEST

GENERAL

Energy Northwest, a municipal corporation and a joint operating agency of the State of Washington, was organized in January 1957 pursuant to the Act. Energy Northwest was formerly known as Washington Public Power Supply System. The name was officially changed to Energy Northwest on June 2, 1999. Energy Northwest has authority, among other things, to acquire, construct and operate plants, works and facilities for the generation of and transmission of electric power and energy and to issue bonds and other evidences of indebtedness for such purposes. Energy Northwest has the power of eminent domain, but is specifically precluded from the condemnation of any plants, works or facilities owned and operated by any city, public utility district or investor-owned utility. Energy Northwest is exempt from federal income tax and has no taxing authority.

Energy Northwest owns and operates Columbia and Packwood, which are currently in operation, and have current net design electric ratings of 1,174 MW and 27.5 MW, respectively. Energy Northwest also owns and operates the Nine Canyon Wind Project, which has a maximum generating capacity of 95.9 MW. Energy Northwest had four nuclear electric generating projects that have been terminated: Projects 1, 3, 4 and 5. For discussions concerning the termination of Projects 1, 3, 4 and 5, see "—PROJECT 1," "—PROJECT 3" and "—PROJECTS 4 AND 5."

Each of Energy Northwest's projects is treated and accounted for by Energy Northwest as a separate utility system, with the exception of Projects 4 and 5, which together comprised a single utility system. Under Washington law, a joint operating agency may create separate special funds for each of its utility systems and Energy Northwest has done so. The resolutions of Energy Northwest pursuant to which its various series of bonds are issued provide that the income, receipts and revenues of each utility system are pledged solely to the payment of obligations incurred in connection with that utility system. The financial statements of Energy Northwest Projects for the year ended June 30, 2024, included in this Official Statement as Appendix C, have been audited by Baker Tilly US, LLP, independent accountants, as stated in their report appearing therein.

ENERGY NORTHWEST INDEBTEDNESS

The following table sets forth the principal amounts of revenue bonds and refunding revenue bonds issued by Energy Northwest and outstanding as of March 31, 2025. This table does not include information with respect to the Columbia 2024A/B Notes, which had an outstanding balance of $108,500,000 as of March 31, 2025, which will be repaid with a portion of the proceeds of the Columbia 2025-B (Taxable) Bonds. See "INTRODUCTION."

ENERGY NORTHWEST REVENUE BONDS
OUTSTANDING AS OF MARCH 31, 2025

REVENUE BONDS	PRINCIPAL AMOUNT
PROJECT 1:	
Electric Revenue Refunding Bonds	$ 801,805,000
COLUMBIA:	
Electric Revenue and Refunding Bonds	$ 3,143,000,000
PROJECT 3:	
Electric Revenue Refunding Bonds	$ 937,700,000
TOTAL NET BILLED REVENUE BONDS	$ 4,882,505,000
Nine Canyon Wind Project Revenue Bonds[(1)]	$ 28,005,000

(1) Bonneville is not a party to any agreements that secure payment of the Nine Canyon Wind Project Revenue Bonds.

Bonneville manages its overall debt portfolio, which includes both Bonneville's repayment obligations to the United States Treasury and debt that is secured by Bonneville's financial commitments, to meet the objectives of (i) minimizing the cost to Bonneville's ratepayers; (ii) maximizing Bonneville's access to its lowest cost capital sources to meet future capital needs; and (iii) maintaining sufficient financial flexibility to meet Bonneville's financial requirements. See "THE BONNEVILLE POWER ADMINISTRATION—BONNEVILLE FINANCIAL OPERATIONS" in Appendix A.

Since 2001, Energy Northwest and Bonneville have worked together to refinance certain maturities of outstanding Net Billed Bonds so that the weighted average maturities more closely match the originally expected useful lives of the related Net Billed Project facilities. These refundings are known as "Regional Cooperation Debt."

In September 2018, the Energy Northwest Executive Board adopted a motion supporting the extension of Regional Cooperation Debt through Energy Northwest's fiscal year (July 1 through June 30) 2030 ("Energy Northwest Fiscal Year"). The Energy Northwest Board must approve each series of Net Billed Bonds. Energy Northwest and Bonneville estimate that the aggregate potential principal amount of additional refinancing Net Billed Bonds to be issued through Bonneville's Fiscal Year 2030 could be up to $2.4 billion. In 2024, Energy Northwest issued $189,305,000 of Electric Revenue Refunding Bonds under this second phase of Regional Cooperation Debt, and a portion of the Series 2025-A Bonds are Regional Cooperation Debt.

The current phase of Regional Cooperation Debt refinancings have and will have the effect of freeing up amounts in the Bonneville Fund which otherwise would have been used to fund the repayment of the principal of the refunded Net Billed Bonds. In addition, this phase of Regional Cooperation Debt also includes the issuance of Net Billed Bonds to fund a portion of the interest coupon payments allocable to unamortized bond premiums related to certain outstanding Net Billed Bonds. The freed up funds resulting from the refinancings or issuance of Net Billed Bonds for interest coupon payments would enable Bonneville (i) to make payments to reduce the outstanding principal amount of bonds issued by Bonneville to the United States Treasury to help restore or preserve Bonneville's available capacity of its United States Treasury Borrowing Authority or (ii) to directly fund Bonneville capital investments.

Pursuant to the 2024 Loan Agreement, the amount of the Columbia 2024A/B Notes is not to exceed $120,000,000, maturing on December 16, 2026. Debt service on the Columbia 2024A/B Notes are payable on parity with the outstanding Columbia Electric Revenue Bonds, including the Columbia 2025-A/B Bonds. As of March 31, 2025, Energy Northwest had a balance outstanding of $108,500,000 on the Columbia 2024A/B Notes, which is expected to be repaid with a portion of the proceeds of the Columbia 2025-B (Taxable) Bonds.

ORGANIZATIONAL STRUCTURE

Energy Northwest currently has a membership of 29, consisting of 24 public utility districts and the cities of Centralia, Port Angeles, Richland, Seattle and Tacoma, all located in the State of Washington. Any public utility district and any municipal entity within the State of Washington authorized to engage in the business of generating or distributing electricity may join Energy Northwest.

Energy Northwest has its principal office in Richland, Washington. The Board of Directors of Energy Northwest is comprised of 29 utility members, one from each of the member utilities. Pursuant to the Act, the powers and duties of the Board of Directors are limited to (1) final authority on any decision to acquire, construct, terminate or decommission any power plants, works and facilities, except that once such a final decision is made with respect to a nuclear power plant, the Executive Board has authority to make all subsequent decisions regarding such plant and any of its components; (2) the election and removal of, and establishment of salaries for, the five members of the Executive Board elected from among the members of the Board of Directors; and (3) the selection and appointment of three of the six members of the Executive Board who are outside directors. All other powers and duties of Energy Northwest, including but not limited to the authority to sell any power plant, works and facilities, are vested in the Executive Board.

The Act provides that five of the members of the Executive Board of Energy Northwest are elected by the Board of Directors from among its members and six are outside directors representative of policy makers in business, finance or science, or having expertise in the construction or management of facilities such as those owned by Energy Northwest. Three of these six outside directors are selected by the Board of Directors and three by the Governor of the State of Washington subject to confirmation by the Washington State Senate.

The five members of the Executive Board who are elected from among the Board of Directors serve for four-year terms and may be removed by a majority vote of the Board of Directors. The other members of the Executive Board serve for four-year terms and may be removed by the Governor of the State of Washington for incompetence, misconduct or malfeasance in office; provided, however, the three members appointed by the Governor may be removed without cause prior to their confirmation with the consent of the Washington State Senate. The Chief Executive Officer and other staff of Energy Northwest serve at the will of the Executive Board.

EXECUTIVE BOARD

Present Executive Board members are listed below.

Name	Occupation	Term Expires
John Saven, Chair	Retired Utility Executive	June 2028
Curt Knapp, Vice Chair	Public Utility District Commissioner	June 2026
Bill Gordon, Secretary	Public Utility District Commissioner	June 2026
James Moss, Assistant Secretary	Retired Executive	June 2026
Arie Callaghan	Public Utility District Commissioner	June 2026
Marc Daudon	Management Consultant	June 2026
Janet Herrin	Retired Utility Executive	June 2025
Johnny (Jack) Janda	Public Utility District Commissioner	June 2026
Dave McKenzie	Public Utility District Commissioner	June 2026
Bill Pitesa	Retired Nuclear Executive	June 2026
Tim Sheldon	Retired Washington State Senator	June 2028

MANAGEMENT

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

Name	Position	Nuclear Industry Experience
Robert E. Schuetz	Chief Executive Officer	45 years
William G. Hettel	Executive Vice President/Chief Nuclear Officer	43 years
Scott A. Vance	Vice President for Corporate Governance; General Counsel	36 years
Cristina M. Reyff	Vice President for Corporate Finance, Chief Financial and Risk Officer	17 years
Greg V. Cullen	Vice President for Energy Services and Development	31 years
Dawn M. Sileo	Vice President for Corporate Support Services	21 years
		Utility Industry Experience
Marcus A. Harris	Chief of Executive Projects	16 years

EMPLOYEES

As of January 1, 2025, Energy Northwest employed 1,085 employees. Of these employees, 307 are members of the International Brotherhood of Electrical Workers ("IBEW"), 120 are members of the United Steel Workers ("USW") and four are members of the Hanford Atomic Metal Trades Council ("HAMTC") unions. The IBEW union members comprise the Administrative, Nuclear, Travelers and Plant bargaining groups; the USW union members constitute the Security Force bargaining group; and the HAMTC union members comprise part of the Standards Lab Instrument Specialists. The Administrative and Plant bargaining agreements are in place through 2027. The Nuclear, HAMTC and Travelers bargaining agreements are in place through 2028. The Nuclear Security Officer bargaining agreement expired in 2024 and remains in negotiations for a successor agreement. A mediator has been retained to provide assistance and a new agreement is expected to be achieved in the near future. Energy Northwest considers labor relations to be satisfactory and uses third parties when differences come up between Energy Northwest and the respective union that cannot be resolved, to ensure effective closure.

INVESTMENT POLICY

Energy Northwest invests its funds in accordance with the authority provided by the Electric Revenue Bond Resolutions, and its investment policy covers all funds and investment activities under the direct authority of Energy Northwest. The investment policy has been reviewed and accredited by the Washington Public Treasurers Association ("WPTA") since 2015. WPTA has recertified the policy in March 2025, with anticipated approval by the Board of Directors in June 2025.

Investment securities purchased consist generally of obligations of, or obligations the principal of and interest on which is unconditionally guaranteed by, the United States of America or other investment securities permitted by the related Net Billed Resolutions. The current investment policy does not permit the purchase of leveraged or derivative-based investments.

For further information on the types of investments in which Energy Northwest is permitted to invest its funds, see Appendix H—"SUMMARY OF CERTAIN PROVISIONS OF THE ELECTRIC REVENUE BOND RESOLUTIONS AND THE SUPPLEMENTAL ELECTRIC REVENUE BOND RESOLUTIONS—Investment of Funds (Section 508)."

RETIREMENT PLANS AND OTHER POST-EMPLOYMENT BENEFITS

Energy Northwest offers a 401(k) Deferred Compensation Plan, a 457 Deferred Compensation Plan, State of Washington (the "State") pension program and Other Post-Employment Benefits. For information on these plans including benefits, investment returns and sensitivity, see Notes 6, 7 and 12 in the Audited Financial Statements of Energy Northwest Projects for the Year Ended June 30, 2024, included herein as Appendix C.

Energy Northwest participates in the State Public Employees Retirement System ("PERS"), which consists of defined benefit Plans 1 and 2 and a hybrid defined benefit/defined contribution Plan 3. PERS participants who joined the system by September 30, 1977 are Plan 1 members. Members now have the option of choosing Plan 2 or Plan 3.

State law requires systematic actuarial funding to finance the retirement plans. Actuarial calculations to determine employer and employee contributions are prepared by the Office of the State Actuary ("OSA"), a nonpartisan legislative agency charged with advising the legislature of the State (the "State Legislature") and State Governor on pension benefits and funding policy. Contributions by both employees and employers are based on gross wages. State law requires systematic actuarial funding to finance the retirement plans. To calculate employer and employee contribution rates necessary to pre-fund the plans' benefits, OSA uses actuarial cost and asset valuation methods selected by the State Legislature as well as economic and demographic assumptions. The State Legislature adopted the following economic assumptions for contribution rates beginning July 1, 2024: (1) 7.0% per annum rate of investment return (as stated in the State Department of Retirement Systems ("DRS") Annual Comprehensive Financial Report for the year ended June 30, 2024); (2) general salary increases of 3.25% per annum; and (3) 2.75% rate of Consumer Price Index increase. The assumed long-term investment return used as the discount rate for determining the liabilities for each plan is 7.0% for the calculation of contribution rates for the 2024-26 Biennium. The long-term investment return assumption is used as the discount rate for determining the liabilities for a plan. Most retirement funds are invested by the Washington State Investment Board, a 15-member board created by the State Legislature. The current contribution rates of employees and employers for PERS are 9.11% for employers and for employees 6.00% for PERS Plan 1, 6.36% for PERS Plan 2 and vary between 5.0% to 15.0% for PERS Plan 3.

All DRS retirement plans are funded by a combination of funding sources: (1) contributions from the State for certain plans; (2) contributions from employers (including the State as employer and Energy Northwest and other governmental employers); (3) contributions from employees; and (4) investment returns.

Pension costs for Energy Northwest employees are calculated and allocated to each Energy Northwest business unit based on direct labor dollars. Required contributions in Energy Northwest Fiscal Year 2024 was $14,100,000. About 92.5% of the required contributions to the PERS plans described above were paid by Columbia. Required contributions in Energy Northwest Fiscal Year 2023 were $15,516,000.

The State Actuary's actuarial valuation, using the Entry Age Normal ("EAN") cost method, for PERS Plan 1 and PERS Plans 2 and 3 as of June 30, 2023, showed an 80% funded ratio (unfunded liability of $2.140 billion) and an 97% funded ratio (unfunded liability of $1,653 billion), respectively. Using the EAN cost method, the State Actuary's actuarial valuation for PERS Plan 1 and PERS Plans 2 and 3 as of June 30, 2022, showed a 75% and 97% funded ratio, respectively.

While Energy Northwest's contributions represent its full current liability under the DRS systems, any unfunded pension benefit obligations could be reflected in future years as higher contribution rates. Based on estimates on the OSA website, it is expected that the contribution rates for employees and employers in PERS Plans 2 and 3 will decrease in the coming years. The OSA website (which is not incorporated into this Official Statement by reference) includes information regarding the values, funding levels and investments of these retirement plans.

The Governmental Accounting Standards Board ("GASB") has implemented pension regulations that require employers, including Energy Northwest, to report their pension liabilities on a generally accepted accounting principles ("GAAP") basis rather than a funding basis. Beginning with its 2015 financial statements, Energy Northwest reported its proportionate share of the net plan asset or liability for each pension plan in which Energy Northwest employees participate. The liability is based on the actuarial present value of projected benefit payments to periods of employee service, a discount rate that considers the availability of plan assets and recognition of projected investment earnings. The DRS will determine each participating employers' proportionate share of the plan liability and OSA will determine each plan's accounting valuation. The GASB rules impact accounting for pensions and not the funding status of the plans calculated by OSA or pension contribution rates that are set based on statutory assumptions. See Note 6 in the financial statements of Energy Northwest Projects for the year ended June 30, 2024, included as Appendix C herein, for Energy Northwest's share of net liability and expenses.

Energy Northwest has two liabilities related to other post-employment benefits ("OPEB"). The first is related to grandfathered life insurance for retirees and has been determined to be immaterial to the financial statements as a whole for reporting. The second is an implicit benefit received from employees receiving medical insurance through the State Department of Retirement Systems following retirement. Energy Northwest Fiscal Year 2024 total liability was $24.5 million. Like the liability related to the PERS retirement plan Energy Northwest is not directly responsible for the recovery of this cost nor does it make any direct payments for this benefit to retirees.

THE COLUMBIA GENERATING STATION

Description

The Columbia Generating Station is an operating nuclear electric generating station located about 160 miles southeast of Seattle, Washington, near Richland, Washington on the DOE's Hanford Reservation. The site has been leased from DOE and the lease is scheduled to terminate on January 1, 2052.

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

Columbia commenced commercial operation in 1984 and has a current net design electric rating of 1,174 MW. Columbia consists of a General Electric Company-designed boiling water reactor and nuclear steam supply system, a Westinghouse turbine-generator and the necessary transformer, switching and transmission facilities to deliver the output to the transmission facilities of the Federal System located in the vicinity of Columbia. Bonneville has acquired the entire capability of Columbia under the Columbia Net Billing Agreements. See "SECURITY FOR THE NET BILLED BONDS—NET BILLING AND RELATED AGREEMENTS."

Columbia consists of the following structures: the reactor building, the radioactive waste building, the turbine-generator building, the diesel generator building, the service building, six mechanical-draft evaporative cooling towers, the circulating water pumphouse and the river makeup water pumphouse. Makeup water to replace evaporative losses is obtained from the Columbia River by means of three makeup water pumps. Emergency power is supplied to Columbia by diesel generators sized to sustain all essential plant loads without the need for outside power sources. Columbia also includes the Independent Spent Fuel Storage Installation facility. For additional information concerning the Independent Spent Fuel Storage Installation facility, see "Nuclear Fuel" below.

Columbia also includes the plant engineering center and other office and support facilities located adjacent to the main plant, the plant support facility located one mile southwest of the main plant and various administrative service buildings located in Richland, Washington, approximately ten miles from the site.

Low-level radioactive waste generated at Columbia is disposed of at a commercial facility located on the Hanford Reservation.

Management Discussion of Operations

All the power from Columbia is sold at cost to Bonneville through the Columbia Net Billing Agreements. Energy Northwest has a maintenance, operating, fuel and capital budget for Columbia of $890.3 million for the 2025 Energy Northwest Fiscal Year.

The cost of production, using industry standard methodology (such cost calculation methodology includes general and administration, but excludes debt service, taxes, depreciation, and decommissioning costs), of Columbia electricity is budgeted at

$45.61 per megawatt-hour ("MWh") for the Energy Northwest Fiscal Year 2025. This budgeted cost is higher than the $29.34 per MWh for the Energy Northwest 3rd Amended Fiscal Year 2024 Budget because Fiscal Year 2025 includes a refueling and maintenance outage.

Energy Northwest continues to focus on plant reliability, availability and increasing gross plant capacity as the primary factors to reduce the cost of power. Initiatives to reduce losses of generation, such as reducing outage length and reducing or eliminating the occurrences of forced outages, are continually being evaluated and implemented.

Recent Developments

With a 100% carbon-free energy portfolio, Energy Northwest is well-positioned to lead Washington state in developing new clean energy generation resources and advancing transportation electrification projects. The 2019 passage of the Clean Energy Transformation Act provides public power with the opportunity to help Washington meet its carbon-reduction goals while maintaining a reliable and affordable electric grid.

In August 2023, the Tri-City Development Council ("TRIDEC") formed the Energy Forward Alliance ("EFA") to achieve a clean energy vision to transform Mid-Columbia communities, lead the region's clean energy future and inspire those far and wide to participate in a sustainable future. EFA focuses on the transition to a reliance and resilient clean energy future in the Mid-Columbia region. EFA includes foundational efforts from local businesses, universities and community leaders and looks to working with a broad array of regional partners and collaborators to invest, innovate and inspire the new energy future.

Energy Northwest is taking action to reduce its environmental impact, including pursing clean energy agencywide, providing clean energy sources and as part of the EFA. In June 2024, the Columbia Generating Station successfully transitioned to small quantity waste generator status ("SQG") as a result of ongoing efforts to reduce hazardous waste generation. Other Energy Northwest facilities maintained SQG status. In addition, Energy Northwest continues to pursue options for reducing greenhouse gas emissions from indirect sources, including reducing fuel consumption by replacing fleet vehicles with more fuel-efficient vehicles and implementing energy efficiency upgrades in buildings.

In December 2024, the nuclear industry recognized Columbia Generating Station and its workforce as a top performing plant for achieving the highest levels of safety, reliability and operational performance. This was the third consecutive two-year review period in a row the Columbia team received the recognition.

Columbia Generating Station's last refueling outage was in May through June 2023. The station has been steadily producing power since it came back online after its 2023 refueling outage. In November 2024, Columbia Generating Station set a new record of 513 days online - it's second longest run in its history. Columbia is one of a few plants in the nation that has gone more than six years without an unplanned shutdown.

Beginning on April 11, 2025, Energy Northwest took Columbia offline for its 27th refueling outage. During the biennial outage, expected to last 56 days, Energy Northwest will replace about a third of the 764 nuclear fuel assemblies in Columbia's core with new fuel.

In October 2024, Energy Northwest reached an agreement with Amazon to invest in the initial feasibility phase of developing a small modular reactor ("SMR") on the site of Project 1 near the Columbia Generating Station. Amazon's funding will support two years of comprehensive environmental, safety, permitting, licensing and risk analyses, leading to Energy Northwest's submission of a construction permit application. The SMRs will be the Xe-100 design, a high-temperature gas-cooled reactor developed by X-Energy Reactor Company, LLC ("X-energy"). Each Xe-100 module can provide 80 MW of continuous electricity. To aid in ensuring that eventual construction of an Xe-100 SMR is prudent, Amazon is also investing in X-energy. Energy Northwest entered a joint development agreement with X-energy in 2023. See "SMALL MODULAR REACTORS."

In 2023, Energy Northwest announced a $10 million investment from Puget Sound Energy to accelerate Energy Northwest's program examining the feasibility of developing and deploying a next-generation SMR. The financial commitment by Puget Sound Energy adds to the nearly $1 million in combined investment in the feasibility phase from 17 northwest public utilities. Energy Northwest is partnering with Argonne National Laboratory in Illinois to advance research on new nuclear reactor designs through the Department of Energy's Gateway for Accelerated Innovation in Nuclear voucher program.

Energy Northwest estimates Columbia's production cost of power will average 3.79 cents per kilowatt-hour during its 2024-2025 fuel cycle, down from 4.53 cents, adjusted for inflation, nearly 10 years ago.

In 2024, Energy Northwest received first-place safety awards from the Northwest Public Power Association and the American Public Power Association. For the tenth consecutive, Energy Northwest was designated a military friendly employer, recognizing its commitment to and programs for veterans and their families. The Association of Washington Business recognized Energy Northwest's dedication to providing employment opportunities for veterans with the 2023 Veterans & Families Award.

Energy Northwest commissioned Bisconti Research in June 2022 to conduct State-wide polling in Washington to gauge the public's view of nuclear energy. The survey found 87% view nuclear energy as important for meeting the nation's future electricity needs; 82% see nuclear energy as important for meeting Washington State's future electricity needs; and 73% favor the use of nuclear energy as one of the ways to provide electricity in Washington.

In the transportation sector, Energy Northwest and partners installed a network of direct current fast-charging stations along U.S. Route 12 in Washington to help alleviate the "charging gap" or long distances between charging stations that make travel through underserved corridors difficult for electric vehicles. In 2024, Energy Northwest was notified that it was awarded a $14.6 million grant from the U.S. Department of Transportation to install 40 electric vehicle fast chargers and 12 Level 2 chargers across western Washington and Oregon. See "Energy Services and Development."

The passage of the Inflation Reduction Act (the "IRA") and the Infrastructure Investment and Jobs Act (the "IIJA") allows not-for-profit public power utilities like Energy Northwest to directly receive federal incentive payments for a variety of generation and infrastructure projects, including those undertaken at Columbia. Energy Northwest has established an internal team to research and analyze the potential impacts of the IRA and IIJA pending the issuance of regulatory guidance on the implementation of these provisions. No assurance can be given as to the potential benefits of the IRA or IIJA to Energy Northwest or any of its projects.

Operating Performance

Columbia received an operating license in December 1983, commenced commercial operation in December 1984, and has been in operation since that time. Since commencing commercial operation, Columbia has operated at a cumulative capacity factor of 78.5% and has generated 306,275,743 MWh (net of station use) of electric power through January 2025. In the ten Energy Northwest Fiscal Years ending June 30, 2024, however, the cumulative capacity factor was 91.9%.

Successful implementation of employee performance enhancement initiatives at Columbia has contributed to significant positive results in plant performance. The generation for Energy Northwest Fiscal Year 2024 was 9,928 GWh. Columbia produced 8,630 GWh of electricity in Energy Northwest Fiscal Year 2023, which included a refueling outage. The Energy Northwest Fiscal Year 2024 generation increase of 15.0% was because Energy Northwest Fiscal Year 2023 included a refueling outage and 93 GWh of coast down credit (a prudent utility practice to optimize fuel efficiency as part of General Electric's fuel design).

Annual Costs

Annual costs for Columbia are derived from the audited financial statements for Energy Northwest Fiscal Years ended June 30, 2023 and 2024 and are shown below. The information is developed on a cost basis with depreciation calculated on the straight-line method by major components based on expected useful life.

Statement of Operations[(1)]
(Dollars in Thousands)

Cost Category	Energy Northwest Fiscal Year 2023	Energy Northwest Fiscal Year 2024
Operations, Maintenance and Overhead	$242,857	$208,470
Nuclear Fuel	47,114	60,497
Generation Taxes	4,264	4,435
Decommissioning	35,356	42,344
Depreciation and Amortization	103,406	105,939
Investment Income	(4,571)	(10,725)
Interest Expense and Discount Amortization	116,829	118,323
DOE Settlement	(2,154)	(15,037)
Capital Contributions	(9)	(5)
Other Expense/(Revenue)	(25,433)	(3,250)
Total Costs	$517,659	$510,991
Net Generation (GWhs)	8,630	9,928

(1) Dollar amounts derived from audited 2023 and 2024 Energy Northwest financial statements.

Capital Improvements

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

In Energy Northwest Fiscal Year 2024, Energy Northwest spent approximately $102.3 million on capital improvements at Columbia. Energy Northwest expects to spend approximately $256.8 million in Energy Northwest Fiscal Year 2025. The capital improvements at Columbia are expected to include plant and facility modifications, information technology improvements, and replacement of various pieces of equipment.

The following table shows the expected capital improvements (including possible extended power uprate ("EPU") improvements, as discussed below) at Columbia through Energy Northwest's Fiscal Year 2035, most of which are expected to be financed with Columbia Electric Revenue Bonds.

Expected Capital Improvements
(As of March 5, 2025)
(Dollars in Thousands)

Energy Northwest Fiscal Year	Total Capital
2025	$256,821
2026	278,400
2027	580,911
2028	378,276
2029	402,735
2030	265,959
2031	534,592
2032	274,778
2033	299,197
2034	162,122
2035	196,466

Certain of these capital expenditures are expected to be funded or reimbursed by amounts received by Energy Northwest from the Department of Energy pursuant to settlements for breach of contract actions against the United States of America for its failure to dispose of spent nuclear fuel and high-level radioactive waste for the periods from July 1, 2015, through at least June 30, 2025. See "—NET BILLED PROJECTS LITIGATION AND CLAIMS."

Energy Northwest is evaluating the feasibility of an EPU initiative at Columbia with a current target implementation as early as 2031. The total capital amounts listed in the table above include capital related to EPU included in the Columbia Long-Range Capital Plan. The projected capital spending related to EPU for Energy Northwest Fiscal Years 2025 and 2026 are $12,049,000 and $75,578,000, respectively. Preliminary studies indicate there would be approximately $700 million of additional capital associated with Energy Northwest Fiscal Years 2026 through Energy Northwest Fiscal Year 2035. Additionally, required funding amounts related to an EPU may shift between years to accomplish EPU in 2031. If implemented, EPU could increase Columbia's generating capacity by approximately 10-15% over its net design electric rating. To implement the EPU, Energy Northwest would need licensing approval from the NRC, would need to update the National Pollutant Discharge Elimination System permit and require an amendment to the Columbia Generating Station Site Certification Agreement issued by the Energy Facility Site Evaluation Council. See "Licenses and Permits." The Energy Northwest Executive Board has approved proceeding with implementation of an EPU on April 17, 2025, contingent upon approval of Bonneville which could occur as early as May 2025.

Nuclear Regulatory Commission Actions

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

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

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

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

To monitor these seven cornerstones, the NRC assigns colors of Green, White, Yellow or Red to specific performance indicators and inspection findings. For performance indicators, a Green coding indicates performance within an expected performance level in which the related cornerstone objectives are met; White coding indicates performance outside an expected range of nominal utility performance but related cornerstone objectives are still being met; Yellow coding indicates related cornerstone objectives are being met, but with a minimal reduction in safety margin; and Red coding indicates a significant reduction in safety margin in the area measured by that performance indicator. For inspection findings, Green findings are indicative of issues that, while they may not be desirable, represent very low safety or security significance. White findings indicate issues that are of low to moderate significance. Yellow findings are issues that are of substantial safety significance. Red findings represent issues that are of high safety significance with a significant reduction in safety margin.

On January 13, 2022, the NRC notified Energy Northwest of a preliminary White finding due to failures to implement and follow radiation protection procedures during Columbia Generating Station's 25th refueling outage ("R25") in 2021. which resulted in uptakes of radioactive materials during a replacement of a heat exchanger. There was a total of 22 workers receiving positive uptakes of radioactive materials. Two of those workers received doses greater than 700 millirem committed effective dose equivalent. No violation of administrative or federal limits occurred. Energy Northwest discussed the uptake event with the NRC staff on March 1, 2022, at a Regulatory Conference to provide additional information supporting Energy Northwest's perspective that the finding is of very low safety significance, or a Green finding. On April 14, 2022, the NRC informed Energy Northwest that although they committed to provide a final decision within 45 days (from March 1, 2022), they received new information that required additional review and the final decision was on hold, pending review of the new information. On May 11, 2023, the NRC informed Energy Northwest that the final characterization of the failure to follow radiation protection procedures was a White finding. In addition, the NRC informed Energy Northwest of an additional performance deficiency of potential low to moderate significance in the radiation protection area related to failure to follow procedures in assessing the dose associated with the workers who received the uptake of radioactive material during the event in R25. The NRC conducted a meeting with Energy Northwest on May 30, 2023, informing Energy Northwest that the failure to assess dose per procedure was an additional performance deficiency and finding with a preliminary White significance characterization. Energy Northwest responded to the NRC in July 2023 accepting the first White finding and responded to the additional preliminary White finding with information and basis explaining Energy Northwest's perspectives that the additional proposed performance deficiency was not a violation of NRC requirements. On November 1, 2023, Energy Northwest received notice from the NRC confirming the violation and significance of the additional performance deficiency as a White finding. See "—NET BILLED PROJECTS LITIGATION AND CLAIMS" regarding tort claims filed relating to this incident. For both White findings root cause analyses were conducted and preparations were made for a planned NRC inspection in which the NRC evaluated Energy Northwest's understanding of the root and contributing causes of the event and findings and the adequacy of corrective actions. Energy Northwest communicated to the NRC in December 2023 of Columbia Generating Station's readiness to be inspected. The NRC inspection was subsequently scheduled to commence March 4, 2024. However, prior to the inspection it was determined through both an additional Energy Northwest review and independent NRC review of inspection readiness that additional work and preparation was required by Energy Northwest prior to the NRC inspection commencing. Consequently, the NRC inspection was postponed to August 19, 2024. In addition to inspecting the White findings the NRC also evaluated Energy Northwest's assessment of the failure to ensure inspection readiness. Prior to these White findings, there were no findings greater than Green at Columbia since November 2016 when a White finding was issued for shipping radioactive material in the incorrect container on public roadways that did not comply with Department of Transportation regulations. As a result of the two white findings, Columbia was placed in the Regulatory Response Column of the NRC's Reactor Oversight Process as discussed below. Placement in the Regulatory Response Column requires the NRC to conduct a supplemental inspection (Inspection Procedure 95001) to validate that Energy Northwest has identified appropriate causes for the two White findings and the corrective actions are adequate. Increased oversight is by implementation of the supplemental inspection. Energy Northwest did not receive additional oversight for the White findings other than through future baseline inspection efforts to validate closure of corrective actions if any are pending completion at the time of the 95001 inspections. On February 25, 2025, the NRC completed the supplemental inspection (Inspection Procedure 95001) and conducted an exit meeting. The NRC issued a final inspection report on April 2, 2025, returning Columbia to the Licensee Response Column of the NRC's Reactor Oversight Process. Placement in the Licensee Response Column returns Columbia to baseline inspection activities.

In September 2023, the NRC identified a chilled work environment in the Operations Department during the NRC's Problem Identification and Resolution Inspection (Inspection Procedure 71152). This routine inspection is conducted every two years. In response, Energy Northwest has conducted an independent assessment of the Operations Department safety culture and initiated other actions to assess and improve safety culture in the Operations Department and in other departments as well. The NRC conducted a special inspection (Inspection Procedure 93100, "Safety-Conscious Work Environment Issue of Concern Followup") the week of May 6, 2024, to assess Energy Northwest's actions to improve the Operations Department safety conscious work environment and the chilled work environment. The NRC did not identify any findings or violations during the inspection. Additionally, the NRC observed some progress with station efforts to address the chilled work environment in the Operations Department and did not issue a formal chilled work environment letter. However, the NRC team remained concerned about the safety conscious work environment in the Operations Department, including the scope of corrective actions, and the pace at which corrective actions were being taken to address the chilled work environment. The NRC also concluded they did not identify any significant issues with safety conscious work environment in other evaluated departments. The NRC plans to conduct an additional follow-up special inspection (Inspection Procedure 93100) the week of July 14, 2025, to further assess adequacy and timeliness of corrective actions and determine the trajectory of the Operations Department chilled work environment. This issue and follow-up inspections do not impact Columbia Generating Station's standing in the NRC's Reactor Oversight Program.

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

Best performing plants are included in the Licensee Response Column where routine (baseline) inspection and staff interaction is the norm. The next level of performance is the Regulatory Response Column, which includes plants that have no more than two White inputs in different strategic performance areas. Plants in this column are subject to NRC inspection follow-up of utility corrective actions. There are three remaining Response Columns, including the Unacceptable Performance Column, which includes plants that are not permitted to operate.

As of April 22, 2025, 89 plants, including Columbia, were listed in the NRC's Regulatory Oversight Process Summary Licensee Response Column, with six plants in the Regulatory Response Column, and no plants in the Multiple/Repetitive Degraded Cornerstone Column, the Degraded Cornerstone Column or the Unacceptable Performance Column.

World Association of Nuclear Operators

Energy Northwest is a member of the World Association of Nuclear Operators ("WANO"), a nonprofit organization that works to unite every company and country with an operating commercial nuclear power plant to achieve the highest possible standards of nuclear safety. WANO works directly with its members to help operators communicate effectively and share information openly. WANO is based in London, England, and has regional centers in Atlanta, Moscow, Paris and Tokyo, and its policies and programs are established on a global level. One of these programs is the peer review, which helps members compare their operational performance against standards of excellence through an in-depth, objective review of operations by an independent team. WANO expects to have a peer review every four years at U.S. nuclear plants. The WANO Corporate Evaluation of Energy Northwest occurred in December 2023, and the report included three areas for improvement and three strengths. Energy Northwest reviews these areas for improvement and is working with WANO to address them with the intent to close these areas for improvement by Fall 2025. The next WANO Corporate Evaluation will occur in 2028. Additionally, WANO performed a peer review of Columbia's station performance in November 2022. Several strengths and a few areas for improvement were noted by the evaluation team and initiatives were put in place for enhancing station performance. Energy Northwest continually reviews its performance according to the evaluation criteria to addresses any areas for improvement. The next WANO station review for Columbia is expected in Fall 2026.

Institute of Nuclear Power Operations

The United States nuclear electric industry created the Institute of Nuclear Power Operations ("INPO") in 1979. The INPO mission is to promote the highest levels of safety and reliability in the operation of nuclear power plants. All United States utilities that operate commercial nuclear power plants, including Energy Northwest, are INPO members. INPO conducts continuum site visits of all United States plants, including Columbia, approximately every four years. WANO peer evaluations occur every four years and alternate with continuum site visits. Additionally, INPO continuum site visits serve as a WANO follow-up peer review. In November 2022, a WANO peer evaluation was conducted with a few areas for improvement and strengths noted. The next INPO continuum site visit occurred in October 2024 with three areas of concern (no strengths are provided as part of these reviews) but overall an exemplary performance. INPO also performs continuous performance monitoring. Key station personnel work directly with their INPO point of contact as part of this continuous performance monitoring to ensure station performance is clearly understood and any gaps to excellence are addressed in a timely manner.

Permits and Licenses

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

A site certification agreement for Columbia was executed with the State of Washington in May 1972. The site certification requires Energy Northwest, among other things, to monitor the environmental effects of plant construction and plant operation, comply with standards set for the consumption and discharge of water and for discharges to the air, and develop an effective emergency plan. The State's Energy Facility Site Evaluation Council ("EFSEC") has also issued a National Pollutant Discharge Elimination System ("NPDES") permit. Columbia's NPDES permit was renewed, with an effective date of July 1, 2023, and expires on June 30, 2028. Columbia has obtained the necessary Certificate of Water Right from the Washington Department of Ecology. The Certificate of Water Right expires when use ceases. The Washington State Department of Natural Resources has entered into a lease with Energy Northwest for that portion of the bed of the Columbia River which encompasses the plant intake and discharge facilities. The Corps has issued a permit for construction and maintenance of the completed river facilities.

In April 2018, Energy Northwest applied for a radioactive air emissions license ("RAEL") from the State through EFSEC and the State's Department of Health ("DOH"). The State regulates radioactive air emissions under Washington Administrative Code, Chapter 246-247. In November 2020, Columbia received a draft RAEL and Energy Northwest submitted comments to such draft. Energy Northwest is awaiting a response to its comments and is continuing to work with EFSEC and DOH to address comments.

Nuclear Fuel

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

Fabrication services through 2031 reloads are provided pursuant to a contract with Global Nuclear Fuel – Americas, LLC. Columbia operates on a 24-month fuel cycle; a 24-month fuel cycle eliminates the need for refueling outages every year and results in increased average generation. To meet the enriched uranium requirements for the reload fuel assemblies, Energy Northwest purchases uranium in various forms and holds them in inventory until needed for fuel fabrication.

As a result of the low market conditions and overall cost of borrowing compared to significantly higher prices forecasted in the future, Energy Northwest issued a request for proposal in 2020 for both near-term and long-term supplies. Energy Northwest made the decision to cover the Energy Northwest Fiscal Years 2027-2030 uranium and enrichment purchases with a long-term supply contact with Orano, a global nuclear fuel cycle company. In addition, Energy Northwest elected to purchase 66,000 KgU of 4.95% enriched uranium from Urenco, a British-German-Dutch nuclear fuel consortium operating several uranium enrichment plants in Germany, the Netherlands, the United States and the United Kingdom, which was delivered in November 2020 and placed into inventory. The costs of acquiring a portion of the fuel for the Columbia Generating Station was reimbursed with Columbia Electric Revenue Bonds issued in 2021. In January 2024, Energy Northwest made the decision to revise the Orano delivery schedule due to growing market uncertainty with the United States ban on Russian Uranium and potential global supply problems. The deliveries were successfully completed in December 2024 and January 2025. The uranium was purchased with a taxable advance under the 2024 Loan Agreement to be refinanced with the Columbia 2025-B (Taxable) Bonds. These purchases combined with existing inventories and contracts provide enough uranium and enrichment to meet the requirements of Columbia through 2037.

Energy Northwest has a contract with DOE that requires DOE to accept title and dispose of spent nuclear fuel. For this future service, Energy Northwest has paid a quarterly fee based on about one dollar per megawatt-hour of net electricity generated and sold from Columbia; however, the District of Columbia Court of Appeals ruled that the DOE had no grounds to collect the waste fees unless the Yucca Mountain project is restarted or Congress passes an alternative disposal plan. DOE ceased collecting the disposal fee from Energy Northwest effective May 16, 2014. To permanently store the spent fuel from the nation's nuclear plants, DOE is evaluating proposed sites for a repository. Although courts ruled that DOE has an obligation to begin taking title to the spent fuel no later than January 31, 1998, currently, there is no known date established when DOE will fulfill this legal obligation and begin accepting spent nuclear fuel. Once DOE begins to accept spent fuel, it will accept the oldest spent fuel first, on a national basis. Because Columbia is a relatively young plant, DOE does not plan to accept any spent fuel from Columbia during the first 10 years of repository operation.

Energy Northwest's Independent Spent Fuel Storage Installation ("ISFSI") at Columbia is a temporary dry cask storage facility intended to store spent nuclear reactor fuel in NRC-approved dry storage casks until the DOE completes its plan for a national repository. The ISFSI consists of two concrete pads storing a total of 36 casks and one additional pad with the capacity of 18 casks. In order to accommodate spent fuel to be generated through the end of the plant's operating license period of December 20, 2043, Energy Northwest is planning the ISFSI facility expansion to store an additional 72 casks. The final phase of the ISFSI pad expansion project was completed in Energy Northwest Fiscal Years 2021-2024. In Fiscal Year 2025, Phase III engineering continued which consists of designing the security systems required to protect the four new storage pads and commissioning was completed in the third quarter of Fiscal Year 2025. The four additional pads will have capacities of 18 casks each. Energy Northwest previously financed a portion of the costs needed for the construction of the existing ISFSI pads from the proceeds of prior issues of Columbia Electric Revenue Bonds.

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

Decommissioning and Site Restoration

GASB implemented an asset retirement obligation ("ARO") standard with Statement No. 83 and has a required implementation date for periods beginning after June 30, 2018. This statement requires that recognition occurs when the liability is both incurred and reasonably estimable. The ARO is to be measured based on the best estimate of the current value of outlays expected to be incurred and that the ARO be measured at the amount of the corresponding liability upon initial measurement. Statement No. 83 requires the ARO to be reviewed annually and adjusted for inflation or deflation. In addition, the statement requires a yearly evaluation of relevant factors that could materially change the estimated asset retirement outlays. Energy Northwest implemented GASB Statement No. 83, effective with the Energy Northwest Fiscal Year 2019 annual reporting. In Fiscal Year 2019, Energy Northwest completed an ARO cost estimate study of Columbia and ISFSI, which was a joint effort between Energy Northwest and Bonneville. The Fiscal Year 2019 ARO cost estimate has been adjusted each year for inflation through Fiscal Year 2023. Energy Northwest and Bonneville completed an updated ARO in April 2024, which increased the estimated liability from Fiscal Year 2023 by $60.6 million.

The NRC has defined decommissioning as actions taken which result in the release of the property for unrestricted use and termination of the nuclear power plant operating license. Currently, the nuclear industry recognizes three alternative methods (decontamination ("DECON"), safe storage ("Safstor") and entombment) to decommission a nuclear power plant, though entombment is no longer part of Energy Northwest's current estimates. A joint decision between Energy Northwest and Bonneville was made to adopt the DECON method for accounting purposes. DECON entails the facility and site containing radioactive contaminants are removed or lowered to levels that permit unregulated use shortly after cessation of operations. Safstor entails placing and maintaining the nuclear facility in a condition that allows it to be safely stored and subsequently decontaminated to levels that permit release for unrestricted use.

The Fiscal Year 2024 Columbia study using DECON extended the scenario's estimated decommissioning activity completion date by two years to June 2099. In Energy Northwest's Fiscal Year 2024, $41.3 million of amortization expense was recognized, the adjustment from the updated study of $60.6 million and the index adjustment for Energy Northwest's Fiscal Year 2024 was $59.5 million resulting in the overall increase in deferred outflow of $78.8 million. The increase from the Fiscal Year 2024 study and the index adjustment increased the estimated liability as of June 30, 2024, from $1.74 billion to $1.86 billion.

Each year the ARO will be evaluated to determine if there are any material changes in timing or costs. An updated ARO estimate was prepared in 2024 and a decision was made to do an updated estimate approximately every five years.

At the time of termination of Columbia and commencing of decommissioning activities, the liability will be decreased as cash expenditures occur through the expected completion date of Fiscal Year 2099. Upon settlement of the liability, there is potential for variances from the original estimates. If there are differences from the estimate and actual payment, a gain or loss on the ARO will be recorded for the difference.

Energy Northwest established a decommissioning and site restoration plan for the ISFSI in 1997. Energy Northwest began making annual payments to a trust fund established pursuant to this plan in 2003 and transferred ownership of the ISFSI trust fund to Bonneville in 2021 in order for Bonneville to manage the ISFSI trust fund along with the primary Columbia decommissioning and site restoration trust funds. Bonneville currently makes monthly contributions to the ISFSI trust fund and expects to continue to do so through 2044. The Columbia cost study completed in April 2024 included the ISFSI, which increased the estimated liability from Fiscal Year 2023 by $15.3 million. The study extended the scenario's estimated decommissioning activity completion date by two years to June 2099 under the DECON scenario and the estimated liability at $25.1 million (in 2024 dollars).

For more details regarding the Columbia decommissioning and restoration trust funds held by Bonneville, see Appendix B-1 to the Official Statement (Note 6 to the Fiscal Year 2024 Audited Financial Statements).

PACKWOOD LAKE HYDROELECTRIC PROJECT

Energy Northwest owns and operates the Packwood Lake Hydroelectric Project ("Packwood"), a hydroelectric generating facility which can generate 26 MW of electricity. Packwood is located near the town of Packwood in Lewis County, Washington, approximately 75 miles southeast of Seattle, Washington. Packwood was granted a Federal Energy Regulatory Commission (FERC) operating license on March 1, 1960 and began commercial operation in June 1964. FERC approved a 40-year operating license for Packwood, effective October 1, 2018.

In Energy Northwest Fiscal Year 2024, production at Packwood totaled 66.31 net GWh, a decrease of approximately 1.3% from the previous year primarily due to lower water levels at Packwood Lake. Energy Northwest Fiscal Year 2024 generation was lower than the last five-year average net generation of 79.49 GWh, and lower than the life to date average per year of 93.00 GWh. Packwood's average availability during the last 15 years has been 98.4%, and has produced 5,579,772 net MWh since commercial operation began. Packwood is a separate system of Energy Northwest and the Packwood participants are required to pay their share of the annual budget of the project, whether the project is producing power or capable of producing power.

NINE CANYON WIND PROJECT

Energy Northwest owns and operates the Nine Canyon Wind Project, a wind energy project, which is capable of generating 95.9 MW of electricity. The project is located on leased land near Kennewick, Washington. The 49 wind turbines of the Nine Canyon Wind Project have a power generating capacity of 1.3 MW each and there are an additional 14 wind turbines with 2.3 MW of power generating capacity each. The turbines were manufactured by Siemens Gamesa Renewable Energy, Inc. (previously BONUS Energy A/S). The project is a separate system of Energy Northwest and the bonds are secured by, and payable solely from, the revenues derived by Energy Northwest under power purchase agreements executed with public utility purchasers. The purchasers are required to pay their share of the annual budget of the project, which includes debt service on the related bonds, whether or not the project is operating or capable of operating.

Power costs for the project billed to the purchasers averaged 5.21 cents per kilowatt hour during Energy Northwest Fiscal Year 2024. The cost of power fluctuates year to year depending on various factors such as wind conditions and unplanned maintenance. In Energy Northwest Fiscal Year 2024, Nine Canyon produced 196.32 net GWh of electricity, compared to 199.75 net GWh in Energy Northwest Fiscal Year 2023. Generation for Energy Northwest's Fiscal Year 2024 decreased from the prior year as a direct result of a decreased average monthly capacity factor (24.0% for Energy Northwest Fiscal Year 2024 versus 24.1% for Energy Northwest Fiscal Year 2023), however wind speed remained steady at 14.99 miles per hour for Energy Northwest Fiscal Year 2024 and Energy Northwest Fiscal Year 2023. Generation for Energy Northwest Fiscal Year 2024 and Energy Northwest Fiscal Year 2023 were both below the five year average gross generation for the Nine Canyon Wind Project.

In September 2022, Energy Northwest established a decommissioning account at U.S. Bank, for the purpose of investing funds received from Phase I and Phase II participants, and will be used to offset future decommissioning-related expenses, which is currently expected to begin in 2030. Energy Northwest is currently evaluating options for the Nine Canyon Wind Project after 2030.

PROJECT 1

Project 1 is a partially completed nuclear electric generating project located about 160 miles southeast of Seattle, Washington, on DOE's Hanford Reservation, approximately one and one-half miles east of Columbia. Project 1 was terminated in May 1994. The Project 1 Project Agreement and the Project 1 Net Billing Agreements ended upon termination of Project 1, except for certain provisions relating to billing and payment processes. See "SECURITY FOR THE NET BILLED BONDS—NET BILLING AND RELATED AGREEMENTS—Payment Procedures" in this Official Statement. The Project 1 Post Termination Agreement facilitates the administration, budgeting and payment processes post termination. After termination, Energy Northwest offered to sell assets in the form of uninstalled operating equipment and construction materials since there was no market for the sale of Project 1 in its entirety. Certain of these assets have been sold.

Energy Northwest has planned for the demolition and restoration of Project 1 and is now maintaining the site to support re-use activities. In addition to funding for the payment of debt service on Project 1 Net Billed Bonds, funding has continued for administrative efforts associated with site maintenance activities for Project 1. Sources of funding are derived through the Project 1 Net Billing Agreements. The Project 1 Post Termination Agreement requires Bonneville to fund this site remediation plan for Project 1, which is expected to be complete in June 2025, with a Post-Maintenance plan for the landfill possibly up to 20 years at a cost estimate of $1.7 million (which was changed from an inert landfill to a special purpose landfill by EFSEC). This revised site restoration plan was submitted to EFSEC, and the landfill closure and Post-Maintenance plan was approved by EFSEC on December 23, 2024. The remaining estimate for site remediation and post-maintenance activities as of January 31, 2025, is $5.5 million in 2024 dollars. It is still undetermined who will cover the Post-Maintenance plan cost for the landfill monitoring with an estimate of up to $1.7 million if the monitoring lasts the full 20 years. Bonneville has placed funds in an external interest-bearing account (which has a balance of approximately $17 million as of December 31, 2024) in order to have sufficient funds for the eventual final remediation, with any funds remaining after final remediation efforts being returned to Bonneville.

PROJECT 3

Project 3 is a partially completed nuclear electric generating project located in southeastern Grays Harbor County, Washington, approximately 70 miles southwest of Seattle, Washington, which was terminated in June 1994. The Project 3 Project Agreement and the Project 3 Net Billing Agreements ended upon termination of Project 3, except for certain provisions relating to billing and payment processes. See "SECURITY FOR THE NET BILLED BONDS—NET BILLING AND RELATED AGREEMENTS—Payment Procedures" in this Official Statement. The Project 3 Post Termination Agreement facilitates the administration, budgeting and payment processes post termination.

After termination, Energy Northwest offered to sell assets in the form of uninstalled operating equipment and construction materials since there was no market for the sale of Project 3 in its entirety. In 1995, a group from Grays Harbor County, Washington, interested in local economic development, formed the Satsop Redevelopment Project. The Satsop Redevelopment Project is a coalition of governments established by inter-local agreement between Grays Harbor County, the Port of Grays Harbor and Public Utility District No. 1 of Grays Harbor County. In 1999, Energy Northwest transferred the Project 3 site properties and facilities (other than the Satsop combustion turbine site) to such local public agencies for purposes of economic development. In connection with that transfer, these local public agencies assumed responsibility for any required site remediation. The Satsop combustion turbine site was sold in 2001 to Duke Energy Grays Harbor LLC for $10,000,000.

PROJECTS 4 AND 5

Projects 4 and 5 were terminated in January 1982. The Project 4/5 Bonds went into default on July 22, 1983. After extended litigation and ultimate settlement, all trusts created under the resolution authorizing the Project 4/5 Bonds were terminated, and Energy Northwest and the trustee under the resolution were released from all of their obligations thereunder.

SMALL MODULAR REACTORS

In July 2023, Energy Northwest and X-energy entered into a joint development agreement for up to 12 Xe-100 advanced SMR in central Washington capable of generating up to a total of 960 MW of carbon-free electricity. Energy Northwest expects to bring the first Xe-100 module online by the early to mid-2030's.

In January 2024, Energy Northwest announced an agreement with Puget Sound Energy to accelerate Energy Northwest's program examining the feasibility of developing and deploying a next-generation SMR. This agreement is a $10 million investment by Puget Sound Energy in Energy Northwest's SMR project feasibility phase, but does not obligate Puget Sound Energy to any future financial commitment nor signify an ownership interest in a developed project. Energy Northwest and supporting entities, including 17 northwest public utilities, have already contributed approximately $10 million to this program.

In addition, the supplemental budget passed by the Washington State Legislature and signed by Governor Inslee on March 29, 2024 included a $25 million proviso to support Energy Northwest's new nuclear development efforts. This funding would come from an account created by the Climate Commitment Act. A ballot initiative was on the November 2024 ballot to repeal the act, but was rejected by the voters. Energy Northwest continues to work with the State of Washington to finalize an agreement to fund up to $25 million related to the development of SMR technology.

In July 2024, the Executive Board approved the formation of Energy Northwest New Nuclear LLC, which is wholly owned by Energy Northwest. The objective of this LLC is to obtain financing for a SMR project and repay such financing under the applicable terms. It is expected that SMRs will be payable from sources other than the payments to be made under the Net Billing Agreements. The LLC will be able to enter into contracts for the construction, operation and sale of power from the project, depending on receiving approval from the Energy Northwest Board of Directors. The Board of Directors is required to approve any new project.

In October 2024, Energy Northwest and Amazon announced an agreement to fund efforts (almost $334 million) to move toward development and deployment of SMR technology in Washington state to advance reliable energy across the Northwest. Through the agreement, Amazon will fund the initial feasibility phase of an SMR project, which is planned to be sited on the site of Project 1 near Columbia. Amazon's funding will support approximately two years of comprehensive environmental, safety, permitting, licensing and risk analyses, leading to Energy Northwest's submission of a construction permit application. The SMRs will be the Xe-100 design, a high-temperature gas-cooled reactor developed by X-energy, a global leader in advanced nuclear reactor and fuel technology. Each Xe-100 module can provide 80 megawatts of full-time electricity. Energy Northwest and X-energy have engaged extensively on plans for an Xe-100 facility since 2020. Under the agreement, Amazon will have the right to purchase electricity from the first project (four modules), which is expected to generate 320 MW of energy capacity. Energy Northwest has the option to further build out the site by adding up to eight additional modules (640 MWs) resulting in a total project generating capacity of up to 960 MWs. This additional power will be available to Amazon and northwest utilities to power homes and businesses.

In December 2024, AtkinsRéalis Group Inc. was selected as the Owner's Engineer for the SMR project. Under the Owner's Engineering Services Contract, AtkinsRéalis will support the design, licensing, construction and commissioning of the SMR project. Work will be supported by the recently opened state-of-the-art 32,000 foot AtkinsRéalis Technology Center ("ATC") in Richland. The ATC is a fully integrated engineering and technology facility dedicated to advancement and testing of technical innovations.

ENERGY SERVICES AND DEVELOPMENT

More than two decades ago, Energy Northwest set out to develop new sources of electricity generation and provide energy and environmental related services to meet the needs of its member utilities and the region. Since 1992, Energy Northwest has provided a wide range of calibration services and chemical/environmental analysis services to utility, municipal, commercial, and nuclear customers along with operations and maintenance services for various hydroelectric locations. Energy Northwest is a founding member of NoaNet, offering access to a fiber-optic cable network licensed from Bonneville and other broadband providers. In Energy Northwest Fiscal Year 2024, it notified the other members of NoaNet that it was reducing its participation from a member to an affiliate. Energy Northwest supports the local economy and DOE by offering facilities for lease to early stage businesses, the Pacific Northwest National Laboratory and Hanford contractors.

Energy Northwest continues to support the electric industry with calibration laboratory services with a solid base of existing customers. The Environmental Laboratory continues to expand its base of customers and provides additional services to the Columbia Generating Station during its refueling outage. In August 2021, Energy Northwest was awarded a contract from Bechtel National Inc. ("BNI") to establish service agreements or extend current warranties with the original equipment manufacturer for the BNI instrumentation at the Hanford Tank Waste Treatment and Immobilization Plant. The contract period for performance was extended through December 31, 2026.

Energy Northwest was the recipient of a Washington State Department of Commerce ("Commerce") grant in 2015, which was finalized in 2017. The Commerce grant was an award of up to $3.0 million under the Washington Clean Energy Funds' Grid Modernization Grant Program. The grant was to develop the Horn Rapids Solar Storage and Training ("HRSST") project. The HRSST project included the development of a four MWdc photovoltaic solar project coupled with a one MW/four MWh basic lithium-ion battery storage. Energy Northwest collaborated and came to agreement with the City of Richland for the Battery Energy Storage System ("BESS") storage portion of the HRSST. The Energy Northwest Board of Directors approved the project; and the City of Richland signed a participant agreement in October 2018. Construction of the BESS was initiated in Energy Northwest's Fiscal Year 2020 and both the solar project (that is not owned by Energy Northwest) and BESS, were completed in Energy Northwest's Fiscal Year 2021 and the project is now operational.

Energy Northwest continues to expand its presence in electric vehicle infrastructure development. In January 2018, Energy Northwest finalized agreements to be the lead agency in the Washington State Department of Transportation Electric Vehicle Infrastructure Transportation Alliance Project. Energy Northwest and partners installed direct current fast-charging stations in central Washington to alleviate the "charging gap" or long distances between charging stations that made cross-state electric vehicle travel difficult. In 2021, Energy Northwest received grants from the Commerce Clean Energy Fund and TransAlta Coal Transition fund to install a network of electric vehicle charging stations along the US 12 corridor. Energy Northwest also received funding from Pacific Power for installation of two electric vehicle charging sites in Dayton, Washington and Naches, Washington and funding from Bonneville Environmental Foundation for an electric vehicle charging site in Walla Walla, Washington. These vehicle charging stations were completed in June 2024.

In November 2023, Energy Northwest and EVCS, one of the largest electric vehicle fast-charging network operators on the West Coast, received $10.3 million from Washington State Department of Transportation's Zero-Emission Vehicle Infrastructure Partnership (ZEVIP) Program to install electric vehicle fast chargers at 10 sites across the northern part of Washington, along State Route 20. EVCS will plan, design, construct, own and operate the new charging stations, while Energy Northwest will manage the grant funding.

In November 2023, Energy Northwest received an additional $3.3 million to install electric vehicle chargers at four sites in Southeastern Washington in the cities of Burbank, Clarkston, Washtucna, and Pullman, Washington. Energy Northwest will plan, design, construct, own and operate the new charging stations.

In February 2024, Energy Northwest and EVCS received $14.6 million from the Charging and Fueling Infrastructure Discretionary Grant Program by the United States Department of Transportation. This award is expected to fund the development of more than 50 chargers across 12 charging locations covering over 500 miles along Highway 101 in western Washington and coastal Oregon. Under a contract with Energy Northwest, EVCS will plan, design, construct, own and operate the new charging stations across all locations.

In 2021, Energy Northwest entered into a lease option agreement with Tucci Energy Services, for the purpose of developing a solar project on undeveloped land located approximately three miles north of Richland. The lease option agreement included the option of leasing up to 300 acres of the unused land for future development. This land is part of 300 acres Energy Northwest purchased from Tri-City Development Council in 2016 for future development.

Energy Northwest has a robust Operations and Maintenance sector that supports public power in the areas of operations and maintenance of generating facilities and electric utility operations. Portland Hydro is a five-year agreement for operating and maintaining two powerhouses on the Bull Run River for the City of Portland, the agreement runs through Fiscal Year 2028. Energy Northwest operates and maintains the 14 MW Tieton project located at Rimrock Lake in Yakima County, Washington owned by the City of Burbank, California, which agreement was extended for 10-years in 2024. Energy Northwest entered into an agreement with Eugene Water and Electric Board ("EWEB") to operate and maintain the Stone Creek Hydro project located on the Oak Grove Fork of the Clackamas River. The agreement is for a five-year period to maintain the 12 MWe project for EWEB and was signed in May 2020.

RISK MANAGEMENT

Insurance

Energy Northwest maintains a risk management and insurance program, which incorporates a combination of self-insurance, commercial insurance and nuclear property and liability insurance. Claims relating to Project 1, Columbia or Project 3 that are not covered by insurance are paid from revenues under the related Project Net Billing Agreements.

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

The Price-Anderson Act provides financial protection for the public in the event of a significant nuclear generation plant incident. The Price-Anderson Act sets the statutory limit of public liability for a single nuclear incident at $16.3 billion. Energy Northwest addresses this requirement through a combination of private insurance and an industry-wide retrospective payment program called Secondary Financial Protection ("SFP"). Energy Northwest has $500,000,000 of liability insurance as the first layer of protection. If any U.S. nuclear generation plant has a significant event that exceeds the liability insurance, every operating licensed reactor in the U.S. is subject to an assessment up to $158,026,000 plus state insurance premium tax. Assessments are limited to $24,714,000 per reactor, per year, per incident, excluding taxes. These assessments, if any, could be paid from reserves, charged through rate adjustments or included in the next rate case. The SFP combines the contribution from 95 operating reactors to create the secondary layer of protection at $15.763 billion. The SFP is adjusted at least every five years to account for inflation and any changes in the number of operating plants. The SFP and liability coverage are not subject to any deductibles.

The Code of Federal Regulations requires nuclear generation plant license-holders to maintain at least $1,060,000,000 nuclear decontamination and property damage insurance and required the proceeds thereof to be used to place a plant in a safe and stable condition, to decontaminate it pursuant to a plan submitted to and approved by the NRC before the proceeds can be used for plant repair or restoration or to provide for premature decommissioning. Through the Nuclear Electric Insurance Limited ("NEIL") mutual insurance company, Energy Northwest has aggregate coverage in the amount of $2,750,000,000, which is subject to a $10,000,000 deductible per accident for natural hazards (damage from a windstorm, flood or earth movement) or a $5,000,000 deductible per accident for other types of damage. For more details regarding the NEIL property and decontamination liability and accidental outage insurance policies for Columbia, See Appendix B-1 to the Official Statement (Note 14 to the Fiscal Year 2024 Audited Financial Statements).

If there is accidental property loss and/or a nuclear release originating from a cyber event, both the nuclear property and liability policies extend coverage as defined above under Code of Federal Regulations and the Price-Anderson Act. Accidental property loss with on-site decontamination has protection up to $3.24 billion, and nuclear liability coverage up to $16.3 billion. Insurance coverage is reviewed annually based on current Energy Northwest needs and known cyber risks and control assessment.

Natural Disaster and Climate Change

Washington State has experienced various natural disasters, including wildfires, mudslides, floods, droughts, windstorms, volcanic eruption (Mount St. Helens in 1980), and earthquakes (in Western Washington). The last earthquake in Eastern Washington was in 1936 and had a magnitude estimated between 6.1 and 6.4.

Climate change may intensify and increase the frequency of extreme weather events, such as drought, wildfires, floods and heat waves. Under Washington law, any person, firm or corporation may be liable if it creates or allows extreme fire hazards to exist and which hazards contribute to the spread of the fires.

Physical Security

Physical security at Columbia is regulated by the NRC 10 CFR 73.55 (Requirements for physical protection of licensed activities in nuclear power reactors against radiological sabotage). This regulation requires each licensee, including Columbia, to have a NRC approved Physical Security Plan, a Training and Qualification Plan, a Safeguards Contingency Plan and a Cyber Security Plan. The requirements that Columbia implements as part of its operating license ensures protection against radiological sabotage and theft of special nuclear material.

Cyber Security

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.

Cyber security at Columbia is regulated by the NRC under 10 CFR 73.54 (Protection of Digital Computer and Communication Systems and Networks). This regulation requires the creation of a comprehensive cyber security program that includes analysis and classification of all digital assets, a structured cyber security defensive architecture, application of rigorous technical controls, and an active process to monitor internal and external risks to ensure protection of digital plant equipment. Columbia fully implemented the requirements of 10 CFR 73.54 as of December 31, 2017.

Overall, Columbia's cyber security program provides protections through four primary methods. The first is physical protection; as a nuclear facility, there is extensive physical security including restricted public access, numerous physical barriers, continuous surveillance, and armed officers with authorization to use deadly force to protect the facility. The second is isolation of plant networks with no access to the internet, which eliminates the risk of attacks from the internet being able to control, modify, or disrupt critical plant networks. The third is implementation of cyber security technical controls inside these isolated and protected networks to provide a robust defense-in-depth. Every individual digital asset is analyzed against a catalog of technical controls which are used to ensure that potential vulnerabilities and attack pathways are adequately mitigated. The fourth is implementation of comprehensive programmatic elements that include administrative controls on personnel, active monitoring, continuous reviews of vendor vulnerabilities and periodic security control updates.

Columbia's last full cyber security program inspection by the NRC was in the Fall of 2024. The NRC concluded that Columbia had adequately implemented the requirements but identified four minor and two very low security significance violations. Columbia is on a two-year inspection cycle on an on-going basis with the next full inspection in the summer of 2026.

In regard to recent cyber security data breaches impacting federal agencies, Energy Northwest has not found any evidence or received notifications that would indicate any direct impact. However, based on conservative recommendations, Energy Northwest has implemented security patches and disabled certain software to further protect from the risk of cyber-attacks.

See "Insurance" for information on Energy Northwest's insurance coverage against costs relating to certain cyber events.

Russian Energy and Sanctions

Energy Northwest is well insulated against future uranium market price increases and/or supply disruptions that could arise from prolonged U.S. sanctions on imports of uranium from Russia into the U.S. Energy Northwest's supply contracts are subject to escalation based on inflation indices. As markets have developed, the spot purchase and long-term purchases have saved Energy Northwest millions of dollars, specifically over $181 million for the spot purchase.

Sanctions against Russia have not and are not expected to adversely impact Energy Northwest, given that all of Energy Northwest's long-term fuel storage and supply contracts are with non-Russian suppliers.

NET BILLED PROJECTS LITIGATION AND CLAIMS

Energy Northwest is a party to various claims and legal actions arising in the normal course of business. The following is a discussion of certain litigation and claims to which Energy Northwest is a party relating to the Net Billed Projects:

Energy Northwest v. United States of America (DOE or "government"). On August 14, 2020, Energy Northwest and the United States entered into an Addendum to Settlement Agreement ("Settlement Agreement") under Energy Northwest v. United States, No. 11-447C (Fed. Cl. filed July 7, 2011). The Settlement Agreement provided that Energy Northwest will be reimbursed by the government for its allowable expenses, as defined in the Settlement Agreement, related to DOE's continued failure to accept used nuclear fuel under the Standard Contract signed between Energy Northwest and DOE in 1983.

Under the Settlement Agreement, Energy Northwest is required to submit a claim for reimbursement to DOE annually for each year of Energy Northwest Fiscal Years through December 31, 2025. The claim submission deadline is January 31 of the calendar year following Energy Northwest's fiscal year end. On January 28, 2022, Energy Northwest submitted its Energy Northwest Fiscal Year 2021 reimbursement claim in the amount $8,698,983.12. On July 29, 2022, Energy Northwest received $8,294,982.47 for Energy Northwest's Fiscal Year 2021 claim. On January 27, 2023, Energy Northwest submitted its Energy Northwest Fiscal Year 2022 reimbursement claim in the amount $23,643,994.26. On July 14, 2023, Energy Northwest received $21,133,969.67 for Energy Northwest's Fiscal Year 2022 claim. On January 31, 2024, Energy Northwest submitted its Energy Northwest Fiscal Year 2023 reimbursement claim in the amount $2,381,842.72. On September 13, 2024, Energy Northwest received $2,326,944.26 for Energy Northwest's Fiscal Year 2023 claim. On January 30, 2025, Energy Northwest submitted its Energy Northwest Fiscal Year 2024 reimbursement claim in the amount $14,370,705.21.

The total reimbursement to date from the government to Energy Northwest for partial breach of the Standard Contract is over $169,502,843, of which over $97,225,249, was reimbursed through the claims process for Energy Northwest Fiscal Years 2013 through 2024.

See also "—THE COLUMBIA GENERATING STATION—Nuclear Fuel."

On April 1, 2024, two tort claims filed pursuant to RCW 4.96 were received by Energy Northwest relating to the May 28, 2021 radioactive uptake event alleging negligence and damages in the amount of $12,500,000 each. See "—THE COLUMBIA GENERATING STATION—Nuclear Regulatory Commission Actions." On August 6, 2024, a federal court judge dismissed the lawsuit with prejudice (it is permanently dismissed and cannot be refiled at a later date), with no settlement or award of fees or costs to either party.

LEGAL MATTERS

The approving opinion of Foster Garvey P.C., Bond Counsel to Energy Northwest, as to the legality of the Series 2025-A/B Bonds will be in substantially the form included in Appendix D-1—"PROPOSED FORM OF OPINIONS OF BOND COUNSEL FOR THE SERIES 2025-A/B BONDS." The opinion of Orrick, Herrington & Sutcliffe LLP, Special Tax Counsel, as to the status of the interest on the Series 2025-A/B Bonds for federal income tax purposes will be in substantially the form included in Appendix E—"PROPOSED FORM OF OPINION OF SPECIAL TAX COUNSEL FOR THE SERIES 2025-A/B BONDS."

Bond Counsel will also render a supplemental opinion with respect to the validity and enforceability of the Net Billing Agreements and the Assignment Agreements. As to the due authorization, execution and delivery of such Net Billing Agreements and the Assignment Agreements by Bonneville and certain other matters relating to Bonneville, Bond Counsel will rely on the opinion of Bonneville's General Counsel. In rendering its opinion with respect to the Net Billing Agreements, Bond Counsel will assume, among other things, (1) the due incorporation and valid organization and existence as a municipality, publicly owned utility or rural electric cooperative, as applicable, of each Participant, (2) the due authorization by such Participant of the requisite governmental or corporate action, as the case may be, and due execution and delivery of the Net Billing Agreements to which such Participant is a party and that all assignments of any Participants' obligations under the Net Billing Agreements were properly made, and (3) with respect to the Participants' obligations under the Net Billing Agreements, no conflict or violations under applicable law. In rendering its opinion as to the enforceability of the Net Billing Agreements against the Participants, Bond Counsel will assume the continued obligations of Bonneville, and performance by Bonneville of its obligations under, the Net Billing Agreements and Assignment Agreements, and such opinion will not address the effect on the enforceability against the Participants if Bonneville is no longer obligated under the Net Billing Agreements and Assignment Agreements or of nonperformance thereunder by Bonneville. The assumption in the prior sentence will not affect Bond Counsel's opinion as to the enforceability of the Net Billing Agreements and Assignment Agreements against Bonneville. In the event a Participant's obligations under the Net Billing Agreements are no longer enforceable against such Participant, it is the opinion of Bond Counsel that Bonneville is obligated under the Net Billing Agreements, the Assignment Agreements and the 1989 Letter Agreement to pay to Energy Northwest the amounts required to be paid by such Participant under the Net Billing Agreements. A copy of the proposed form of supplemental opinion of Bond Counsel is included in Appendix D-2—"PROPOSED FORM OF SUPPLEMENTAL OPINIONS OF BOND COUNSEL FOR THE SERIES 2025-A/B BONDS."

See "SECURITY FOR THE NET BILLED BONDS—NET BILLING AND RELATED AGREEMENTS—Assignment Agreements" for a discussion of Bonneville's agreement to pay directly to Energy Northwest certain amounts that are not paid by a Participant and for a discussion of certain of Bonneville's obligations under the Assignment Agreements.

Certain legal matters, including the enforceability against Bonneville of the Net Billing Agreements and the Assignment Agreements, 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 Norton Rose Fulbright US LLP, New York, New York, Counsel to the Underwriters.

TAX MATTERS

In the opinion of Special Tax Counsel, based upon an analysis of existing laws, regulations, rulings and court decisions, and assuming, among other matters, the accuracy of certain representations and compliance with certain covenants, interest on the Series 2025-A Bonds is excluded from gross income for federal income tax purposes under Title XIII of the Tax Reform Act of 1986, as amended (the "1986 Act"), Section 103 of the Internal Revenue Code of 1986, as amended (the "1986 Code") and Section 103 of the Internal Revenue Code of 1954, as amended (the "1954 Code"). Special Tax Counsel is of the further opinion that interest on the Series 2025-A Bonds is not a specific preference item for purposes of the federal individual alternative minimum tax. Special Tax Counsel observes that interest on the Series 2025-A Bonds included in adjusted financial statement income of certain corporations is not excluded from the federal corporate alternative minimum tax. Special Tax Counsel is of the opinion that interest on the Series 2025-B (Taxable) Bonds is not excluded from gross income for federal income tax purposes under Title XIII of the 1986 Act, Section 103 of the 1954 Code, or Section 103 of the 1986 Code. Special Tax Counsel expresses no opinion regarding any other tax consequences related to the ownership or disposition of, or the amount, accrual, or receipt of interest on, the Series 2025-A/B Bonds. In rendering its opinion, Special Tax Counsel has assumed the accuracy of the opinion of Bond Counsel as to the validity of the Series 2025-A/B Bonds and the due authorization and issuance of the Series 2025-A/B Bonds. A complete copy of the proposed form of opinion of Special Tax Counsel is set forth in Appendix E—"PROPOSED FORM OF OPINION OF SPECIAL TAX COUNSEL FOR THE SERIES 2025-A/B BONDS."

As used herein, "U.S. Holder" means a Beneficial Owner of a Series 2025-A/B Bond that for U.S. federal income tax purposes is an individual citizen or resident of the United States, a corporation or other entity taxable as a corporation created or organized in or under the laws of the United States or any state thereof (including the District of Columbia), an estate the income of which is subject to U.S. federal income taxation regardless of its source or a trust where a court within the United States is able to exercise primary supervision over the administration of the trust and one or more United States persons (as defined in the Code) have the authority to control all substantial decisions of the trust (or a trust that has made a valid election under U.S. Treasury Regulations to be treated as a domestic trust). As used herein, "Non-U.S. Holder" generally means a Beneficial Owner of a Series 2025-A/B Bond (other than a partnership) that is not a U.S. Holder. If a partnership holds Series 2025-A/B Bonds, the tax treatment of such partnership or a partner in such partnership generally will depend upon the status of the partner and upon the activities of the partnership. Partnerships holding Series 2025-A/B Bonds, and partners in such partnerships, should consult their own tax advisors regarding the tax consequences of an investment in the Series 2025-A/B Bonds (including their status as U.S. Holders or Non-U.S. Holders).

SERIES 2025-A BONDS

Title XIII of the 1986 Act, the 1986 Code and the 1954 Code impose various restrictions, conditions and requirements relating to the exclusion from gross income for federal income tax purposes of interest on obligations such as the Series 2025-A Bonds. Energy Northwest and Bonneville have made certain representations and covenanted to comply with certain restrictions, conditions and requirements designed to ensure that interest on the Series 2025-A Bonds will not be included in federal gross income. Inaccuracy of these representations or failure to comply with these covenants may result in interest on the Series 2025-A Bonds being included in gross income for federal income tax purposes, possibly from the date of original issuance of the Series 2025-A Bonds. The opinion of Special Tax Counsel assumes the accuracy of these representations and compliance with these covenants. Special Tax Counsel has not undertaken to determine (or to inform any person) whether any actions taken (or not taken) or events occurring (or not occurring), or any other matters coming to the attention of Special Tax Counsel after the date of issuance of the Series 2025-A Bonds may adversely affect the value of, or the tax status of interest on, the Series 2025-A 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 of the opinion that interest on the Series 2025-A Bonds is excluded from gross income for federal income tax purposes, the ownership or disposition of, or the accrual or receipt of amounts treated as interest on, the Series 2025-A 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 expresses no opinion regarding any such other tax consequences.

Current and future legislative proposals, if enacted into law, clarification of the 1986 Act, the 1986 Code or the 1954 Code or court decisions may cause interest on the Series 2025-A Bonds to be subject, directly or indirectly, in whole or in part, to federal income taxation or 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. The introduction or enactment of any such legislative proposals or clarification of the 1986 Act, the 1986 Code or the 1954 Code or court decisions may also affect, perhaps significantly, the market price for, or marketability of, the Series 2025-A Bonds. Prospective purchasers of the Series 2025-A 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 expresses no opinion.

The opinion of Special Tax Counsel is 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 Series 2025-A Bonds for federal income tax purposes. The opinion is not binding on the Internal Revenue Service (the "IRS") or the courts. Furthermore, Special Tax Counsel cannot give and has not given any opinion or assurance about the future activities of Energy Northwest or Bonneville, or about the effect of future changes in the 1986 Act, the 1986 Code, the 1954 Code or the applicable regulations, the interpretation thereof or the enforcement thereof by the IRS. Energy Northwest and Bonneville have covenanted, however, to comply with applicable requirements of the 1986 Act, the 1986 Code and the 1954 Code.

Unless separately engaged, Special Tax Counsel is not obligated to defend Energy Northwest, Bonneville or the Beneficial Owners regarding the tax-exempt status of the Series 2025-A Bonds in the event of an audit examination by the IRS. Under current procedures, Beneficial Owners would have little, if any, right to participate in the audit examination process. Moreover, because achieving judicial review in connection with an audit examination of tax-exempt bonds is difficult, obtaining an independent review of IRS positions with which Energy Northwest or Bonneville legitimately disagrees may not be practicable. Any action of the IRS, including but not limited to selection of the Series 2025-A Bonds for audit, or the course or result of such audit, or an audit of bonds presenting similar tax issues may affect the market price for, or the marketability of, the Series 2025-A Bonds, and may cause Energy Northwest, Bonneville or the Beneficial Owners to incur significant expense.

For U.S. Holders of Series 2025-A Bonds.

To the extent the issue price of any maturity of the Series 2025-A Bonds is less than the amount to be paid at maturity of such Series 2025-A Bonds (excluding amounts stated to be interest and payable at least annually over the term of such Series 2025-A Bonds), the difference constitutes "original issue discount," the accrual of which, to the extent properly allocable to each Beneficial Owner thereof, is treated as interest on the Series 2025-A Bonds which is excluded from gross income for federal income tax purposes. For this purpose, the issue price of a particular maturity of the Series 2025-A Bonds is the first price at which a substantial amount of such maturity of the Series 2025-A Bonds is sold to the public (excluding bond houses, brokers, or similar persons or organizations acting in the capacity of underwriters, placement agents or wholesalers). The original issue discount with respect to any maturity of the Series 2025-A Bonds accrues daily over the term to maturity of such Series 2025-A 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 U.S. federal income tax basis of such Series 2025-A Bonds to determine taxable gain or loss upon disposition (including sale, redemption, or payment on maturity) of such Series 2025-A Bonds. Beneficial Owners of the Series 2025-A Bonds should consult their own tax advisors with respect to the tax consequences of ownership of Series 2025-A Bonds with original issue discount, including the treatment of Beneficial Owners who do not purchase such Series 2025-A Bonds in the original offering to the public at the first price at which a substantial amount of such Series 2025-A Bonds is sold to the public.

Series 2025-A 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 U.S. federal income tax 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.

Payments on the Series 2025-A/B Bonds generally will be subject to U.S. information reporting and possibly to "backup withholding." Under Section 3406 of the Code and applicable U.S. Treasury Regulations issued thereunder, a non-corporate U.S. Holder of the Series 2025-A/B Bonds may be subject to backup withholding with respect to "reportable payments," which include interest paid on the Series 2025-A/B Bonds and the gross proceeds of a sale, exchange, redemption, retirement or other disposition of the Series 2025-A/B Bonds. The payor will be required to deduct and withhold the prescribed amounts if (i) the payee fails to furnish a U.S. taxpayer identification number ("TIN") to the payor in the manner required, (ii) the IRS notifies the payor that the TIN furnished by the payee is incorrect, (iii) there has been a "notified payee underreporting" described in Section 3406(c) of the

Code or (iv) the payee fails to certify under penalty of perjury that the payee is not subject to withholding under Section 3406(a)(1)(C) of the Code. Amounts withheld under the backup withholding rules may be refunded or credited against a U.S. Holder's federal income tax liability, if any, provided that the required information is timely furnished to the IRS. Certain U.S. Holders (including among others, corporations and certain tax-exempt organizations) are not subject to backup withholding. The failure to comply with the backup withholding rules may result in the imposition of penalties by the IRS.

For Non-U.S. Holders of Series 2025-A Bonds

Subject to the discussion below addressing backup withholding tax requirements, payments of principal of, and interest on, any Series 2025-A Bond to a Non-U.S. Holder, generally will not be subject to any federal withholding tax.

Subject to the discussion below addressing backup withholding tax requirements, any gain realized by a Non-U.S. Holder upon the sale, exchange, redemption, retirement (including pursuant to an offer by the Issuer) or other disposition of a Series 2025-A Bond generally will not be subject to U.S. federal income tax, unless (i) such gain is effectively connected with the conduct by such Non-U.S. Holder of a trade or business within the United States; or (ii) in the case of any gain realized by an individual Non-U.S. Holder, such holder is present in the United States for 183 days or more in the taxable year of such sale, exchange, redemption, retirement (including pursuant to an offer by Energy Northwest) or other disposition and certain other conditions are met.

Under current U.S. Treasury Regulations, payments of principal and interest on any Series 2025-A Bonds to a holder that is not a United States person will not be subject to any backup withholding tax requirements if the Beneficial Owner of the Series 2025-A Bond or a financial institution holding the Series 2025-A Bond on behalf of the Beneficial Owner in the ordinary course of its trade or business provides an appropriate certification to the payor and the payor does not have actual knowledge that the certification is false. If a Beneficial Owner provides the certification, the certification must give the name and address of such owner, state that such owner is not a United States person, or, in the case of an individual, that such owner is neither a citizen nor a resident of the United States, and the owner must sign the certificate under penalties of perjury.

SERIES 2025-B (TAXABLE) BONDS

The following discussion summarizes certain U.S. federal income tax considerations generally applicable to holders of the Series 2025-B (Taxable) Bonds that acquire their Series 2025-B (Taxable) Bonds in the initial offering. The discussion below is based upon laws, regulations, rulings, and decisions in effect and available on the date hereof, all of which are subject to change, possibly with retroactive effect. Prospective investors should note that no rulings have been or are expected to be sought from the IRS with respect to any of the U.S. federal tax consequences discussed below, and no assurance can be given that the IRS will not take contrary positions. Further, the following discussion does not deal with U.S. tax consequences applicable to any given investor, nor does it address the U.S. tax considerations applicable to all categories of investors, some of which may be subject to special taxing rules (regardless of whether or not such investors constitute U.S. Holders), such as certain U.S. expatriates, banks, REITs, RICs, insurance companies, tax-exempt organizations, dealers or traders in securities or currencies, partnerships, S corporations, estates and trusts, investors that hold their Series 2025-B (Taxable) Bonds as part of a hedge, straddle or an integrated or conversion transaction, investors whose "functional currency" is not the U.S. dollar, or certain taxpayers that are required to prepare certified financial statements or file financial statements with certain regulatory or governmental agencies. Furthermore, it does not address (i) alternative minimum tax consequences, (ii) the net investment income tax imposed under Section 1411 of the Code, or (iii) the indirect effects on persons who hold equity interests in a holder. This summary also does not consider the taxation of the Series 2025-B (Taxable) Bonds under state, local or non-U.S. tax laws. In addition, this summary generally is limited to U.S. tax considerations applicable to investors that acquire their Series 2025-B (Taxable) Bonds pursuant to this offering for the issue price that is applicable to such Series 2025-B (Taxable) Bonds (i.e., the price at which a substantial amount of the Series 2025-B (Taxable) Bonds are sold to the public) and who will hold their Series 2025-B (Taxable) Bonds as "capital assets" within the meaning of Section 1221 of the Code.

Prospective investors should consult their own tax advisors in determining the U.S. federal, state, local or non-U.S. tax consequences to them from the purchase, ownership and disposition of the Series 2025-B (Taxable) Bonds in light of their particular circumstances.

For U.S. Holders of Series 2025-B (Taxable) Bonds

Interest. Interest on the Series 2025-B (Taxable) Bonds generally will be taxable to a U.S. Holder as ordinary interest income at the time such amounts are accrued or received, in accordance with the U.S. Holder's method of accounting for U.S. federal income tax purposes.

To the extent that the issue price of any maturity of the Series 2025-B (Taxable) Bonds is less than the amount to be paid at maturity of such Series 2025-B (Taxable) Bonds (excluding amounts stated to be interest and payable at least annually over the term of such Series 2025-B (Taxable) Bonds) by more than a de minimis amount, the difference may constitute original issue discount ("OID"). U.S. Holders of Series 2025-B (Taxable) Bonds will be required to include OID in income for U.S. federal income tax purposes as it accrues, in accordance with a constant yield method based on a compounding of interest (which may be before the receipt of cash payments attributable to such income). Under this method, U.S. Holders generally will be required to include in income increasingly greater amounts of OID in successive accrual periods.

Series 2025-B (Taxable) Bonds purchased for an amount in excess of the principal amount payable at maturity (or, in some cases, at their earlier call date) will be treated as issued at a premium. A U.S. Holder of a Series 2025-B (Taxable) Bond issued at a premium may make an election, applicable to all debt securities purchased at a premium by such U.S. Holder, to amortize such premium, using a constant yield method over the term of such Series 2025-B (Taxable) Bond.

Sale or Other Taxable Disposition of the Series 2025-B (Taxable) Bonds. Unless a nonrecognition provision of the Code applies, the sale, exchange, redemption, retirement (including pursuant to an offer by Energy Northwest) or other disposition of a Series 2025-B (Taxable) Bond will be a taxable event for U.S. federal income tax purposes. In such event, in general, a U.S. Holder of a Series 2025-B (Taxable) Bond will recognize gain or loss equal to the difference between (i) the amount of cash plus the fair market value of property received (except to the extent attributable to accrued but unpaid interest on the Series 2025-B (Taxable) Bond, which will be taxed in the manner described above) and (ii) the U.S. Holder's adjusted U.S. federal income tax basis in the Series 2025-B (Taxable) Bond (generally, the purchase price paid by the U.S. Holder for the Series 2025-B (Taxable) Bond, decreased by any amortized premium, and increased by the amount of any OID previously included in income by such U.S. Holder with respect to such Series 2025-B (Taxable) Bond). Any such gain or loss generally will be capital gain or loss. In the case of a non-corporate U.S. Holder of the Series 2025-B (Taxable) Bonds, the maximum marginal U.S. federal income tax rate applicable to any such gain will be lower than the maximum marginal U.S. federal income tax rate applicable to ordinary income if such U.S. holder's holding period for the Series 2025-B (Taxable) Bonds exceeds one year. The deductibility of capital losses is subject to limitations.

Defeasance of the Series 2025-B (Taxable) Bonds. If Energy Northwest defeases any Series 2025-B (Taxable) Bond, the Series 2025-B (Taxable) Bond may be deemed to be retired for U.S. federal income tax purposes as a result of the defeasance. In that event, in general, a U.S. Holder will recognize taxable gain or loss equal to the difference between (i) the amount realized from the deemed sale, exchange or retirement (less any accrued qualified stated interest which will be taxable as such) and (ii) the U.S. Holder's adjusted U.S. federal income tax basis in the Series 2025-B (Taxable) Bond.

Information Reporting and Backup Withholding. Payments on the Series 2025-B (Taxable) Bonds generally will be subject to U.S. information reporting and possibly to "backup withholding." Under Section 3406 of the Code and applicable U.S. Treasury Regulations issued thereunder, a non-corporate U.S. Holder of the Series 2025-B (Taxable) Bonds may be subject to backup withholding with respect to "reportable payments," which include interest paid on the Series 2025-B (Taxable) Bonds and the gross proceeds of a sale, exchange, redemption, retirement or other disposition of the Series 2025-B (Taxable) Bonds. The payor will be required to deduct and withhold the prescribed amounts if (i) the payee fails to furnish a U.S. taxpayer identification number ("TIN") to the payor in the manner required, (ii) the IRS notifies the payor that the TIN furnished by the payee is incorrect, (iii) there has been a "notified payee underreporting" described in Section 3406(c) of the Code or (iv) the payee fails to certify under penalty of perjury that the payee is not subject to withholding under Section 3406(a)(1)(C) of the Code. Amounts withheld under the backup withholding rules may be refunded or credited against the U.S. Holder's federal income tax liability, if any, provided that the required information is timely furnished to the IRS. Certain U.S. Holders (including among others, corporations and certain tax-exempt organizations) are not subject to backup withholding. The failure to comply with the backup withholding rules may result in the imposition of penalties by the IRS.

For Non-U.S. Holders of Series 2025-B (Taxable) Bonds

Interest. Subject to the discussions below under the headings "Information Reporting and Backup Withholding" and "Foreign Account Tax Compliance Act ("FATCA")—U.S. Holders and Non-U.S. Holders," payments of principal of, and interest on, any Series 2025-B (Taxable) Bond to a Non-U.S. Holder, other than (1) a controlled foreign corporation described in Section 881(c)(3)(C) of the Code, and (2) a bank which acquires such Series 2025-B (Taxable) Bond in consideration of an extension of credit made pursuant to a loan agreement entered into in the ordinary course of business, will not be subject to any U.S. federal withholding tax provided that the Beneficial Owner of the Series 2025-B (Taxable) Bond provides a certification completed in compliance with applicable statutory and regulatory requirements, which requirements are discussed below under the heading "Information Reporting and Backup Withholding," or an exemption is otherwise established.

Disposition of the Series 2025-B (Taxable) Bonds. Subject to the discussions below under the headings "Information Reporting and Backup Withholding" and "Foreign Account Tax Compliance Act ("FATCA,")—U.S. Holders and Non-U.S. Holders," any gain realized by a Non-U.S. Holder upon the sale, exchange, redemption, retirement (including pursuant to an offer by Energy Northwest or a deemed retirement due to defeasance of the Series 2025-B (Taxable) Bond) or other disposition of a Series 2025-B (Taxable) Bond generally will not be subject to U.S. federal income tax, unless (i) such gain is effectively connected with the conduct by such Non-U.S. Holder of a trade or business within the United States; or (ii) in the case of any gain realized by an individual Non-U.S. Holder, such holder is present in the United States for 183 days or more in the taxable year of such sale, exchange, redemption, retirement (including pursuant to an offer by Energy Northwest) or other disposition and certain other conditions are met.

Information Reporting and Backup Withholding. Subject to the discussion below under the heading "Foreign Account Tax Compliance Act ("FATCA")—U.S. Holders and Non-U.S. Holders," under current U.S. Treasury Regulations, payments of principal and interest on any Series 2025-B (Taxable) Bonds to a holder that is not a United States person will not be subject to any backup withholding tax requirements if the Beneficial Owner of the Series 2025-B (Taxable) Bond or a financial institution holding the Series 2025-B (Taxable) Bond on behalf of the Beneficial Owner in the ordinary course of its trade or business provides an appropriate certification to the payor and the payor does not have actual knowledge that the certification is false. If a Beneficial Owner provides the certification, the certification must give the name and address of such owner, state that such owner is not a United States person, or, in the case of an individual, that such owner is neither a citizen nor a resident of the United States, and the owner must sign the certificate under penalties of perjury.

FOREIGN ACCOUNT TAX COMPLIANCE ACT ("FATCA")—U.S. HOLDERS AND NON-U.S. HOLDERS OF SERIES 2025-B (TAXABLE) BONDS

Sections 1471 through 1474 of the Code impose a 30% withholding tax on certain types of payments made to foreign financial institutions, unless the foreign financial institution enters into an agreement with the U.S. Treasury to, among other things, undertake to identify accounts held by certain U.S. persons or U.S.-owned entities, annually report certain information about such accounts, and withhold 30% on payments to account holders whose actions prevent it from complying with these and other reporting requirements, or unless the foreign financial institution is otherwise exempt from those requirements. In addition, FATCA imposes a 30% withholding tax on the same types of payments to a non-financial foreign entity unless the entity certifies that it does not have any substantial U.S. owners or the entity furnishes identifying information regarding each substantial U.S. owner. Under current guidance, failure to comply with the additional certification, information reporting and other specified requirements imposed under FATCA could result in the 30% withholding tax being imposed on payments of interest on the Series 2025-B (Taxable) Bonds. In general, withholding under FATCA currently applies to payments of U.S. source interest (including OID) and, under current guidance, will apply to certain "passthru" payments no earlier than the date that is two years after publication of final U.S. Treasury Regulations defining the term "foreign passthru payments." Prospective investors should consult their own tax advisors regarding FATCA and its effect on them.

The foregoing summary is included herein for general information only and does not discuss all aspects of U.S. federal taxation that may be relevant to a particular holder of Series 2025-B (Taxable) Bonds in light of the holder's particular circumstances and income tax situation. Prospective investors are urged to consult their own tax advisors as to any tax consequences to them from the purchase, ownership and disposition of Series 2025-B (Taxable) Bonds, including the application and effect of state, local, non-U.S., and other tax laws.

ERISA CONSIDERATIONS

The Employees Retirement Income Security Act of 1974, as amended ("ERISA"), and the Code generally prohibit certain transactions between a qualified employee benefit plan under ERISA or tax-qualified retirement plans and individual retirement accounts under the Code (collectively, the "Plans") and persons who, with respect to a Plan, are fiduciaries or other "parties in interest" within the meaning of ERISA or "disqualified persons" within the meaning of the Code. All fiduciaries of Plans should consult their own tax advisors with respect to the consequences of any investment in the Series 2025-A/B Bonds.

RATINGS

Moody's Ratings ("Moody's"), S&P Global Ratings ("S&P") and Fitch Ratings ("Fitch") have assigned the Series 2025-A/B Bonds the ratings of "Aa1" (negative outlook), "AA-" (stable outlook) and "AA" (stable outlook), respectively. Ratings were applied for by Energy Northwest and certain information was supplied by Energy Northwest and Bonneville to such rating agencies to be considered in evaluating the Series 2025-A/B 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 or marketability of the Series 2025-A/B Bonds.

UNDERWRITING

J.P. Morgan Securities LLC ("JPMS"), on behalf of itself and Wells Fargo Bank, National Association ("WFBNA"), and BofA Securities, Inc. (collectively, the "Underwriters"), have jointly and severally agreed, subject to certain conditions, to purchase the Series 2025-A/B Bonds from Energy Northwest and to make a bona fide public offering of such Series 2025-A/B Bonds at not in excess of the public offering prices (or prices corresponding to such yields) set forth on the inside cover pages of this Official Statement. The aggregate Underwriters' compensation under the contract of purchase for the Series 2025-A Bonds is $3,091,228.17 and the aggregate Underwriters' compensation for the Series 2025-B (Taxable) Bonds is $371,492.67. The Underwriters' obligations under the contract of purchase are subject to certain conditions precedent contained in that contract of purchase. The Underwriters will be obligated to purchase all of the Series 2025-A/B Bonds being sold under that contract of purchase if any of the Series 2025-A/B Bonds are purchased.

The Series 2025-A/B Bonds may be offered and sold to certain dealers, banks and others (including underwriters and other dealers depositing such Series 2025-A/B 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.

JPMS has entered into negotiated dealer agreements (each, a "Dealer Agreement") with each of Charles Schwab & Co., Inc. ("CS&Co.") and LPL Financial LLC ("LPL") for the retail distribution of certain securities offerings at the original issue prices. Pursuant to each Dealer Agreement, each of CS&Co. and LPL may purchase Series 2025-A/B Bonds from JPMS at the original issue price less a negotiated portion of the selling concession applicable to any Series 2025-A/B Bonds that such firm sells.

Wells Fargo Securities is the trade name used for the corporate banking, capital markets and investment banking services of Wells Fargo & Company and its subsidiaries, including WFBNA, a member of the National Futures Association, which conducts its municipal securities sales, trading and underwriting operations through the Wells Fargo Bank, N.A. Municipal Finance Group, a separately identifiable department of WFBNA, registered with the U.S. Securities and Exchange Commission as a municipal securities dealer pursuant to Section 15B(a) of the Securities Exchange Act of 1934.

WFBNA, acting through its Municipal Finance Group, has entered into an agreement (the "WFA Distribution Agreement") with its affiliate, Wells Fargo Clearing Services, LLC (which uses the trade name "Wells Fargo Advisors") ("WFA"), for the distribution of certain municipal securities offerings, including the Series 2025-A/B Bonds. Pursuant to the WFA Distribution Agreement, WFBNA will share a portion of its underwriting or remarketing agent compensation, as applicable, with respect to the Series 2025-A/B Bonds with WFA. WFBNA has also entered into an agreement (the "WFSLLC Distribution Agreement") with its affiliate Wells Fargo Securities, LLC ("WFSLLC"), for the distribution of municipal securities offerings, including the Series 2025-A/B Bonds. Pursuant to the WFSLLC Distribution Agreement, WFBNA pays a portion of WFSLLC's expenses based on its municipal securities transactions. WFBNA, WFSLLC, and WFA are each wholly-owned subsidiaries of Wells Fargo & Company.

BofA Securities, Inc. has entered into a distribution agreement with its affiliate Merrill Lynch, Pierce, Fenner & Smith Incorporated ("MLPF&S"). As part of this arrangement, BofA Securities, Inc. may distribute securities to MLPF&S, which may in turn distribute such securities to investors through the financial advisor network of MLPF&S. As part of this arrangement, BofA Securities, Inc. may compensate MLPF&S as a dealer for their selling efforts with respect to the Series 2025-A/B Bonds.

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

WFBNA has extended credit in other transactions to Energy Northwest and in other transactions supported by obligations of Bonneville under lease-purchase agreements.

CONTINUING DISCLOSURE

Pursuant to Rule 15c2-12 under the Securities Exchange Act of 1934, as amended ("Rule 15c2-12"), Energy Northwest and Bonneville will enter into Continuing Disclosure Agreements, to be dated the date of delivery of the Series 2025-A/B Bonds, for the benefit of the owners and beneficial owners of the Series 2025-A/B Bonds, to provide certain financial information and operating data relating to Energy Northwest (the "Energy Northwest Annual Information"), certain financial information and operating data relating to Bonneville (the "Bonneville Annual Information" and, together with Energy Northwest Annual Information, the "Annual Information") and to provide timely notices of the occurrence of certain enumerated events with respect to the Series 2025-A/B Bonds. Energy Northwest Annual Information is to be provided not later than 180 days after the end of Energy Northwest Fiscal Year, commencing with the Energy Northwest Fiscal Year ending June 30, 2025. 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 Bonneville Fiscal Year ending September 30, 2025. The Annual Information and notices of aforesaid enumerated events will be filed 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 nature of the information to be provided and notices of such enumerated events is set forth in Appendix J—"SUMMARY OF THE CONTINUING DISCLOSURE AGREEMENTS."

Energy Northwest has previously entered into continuing disclosure undertakings under Rule 15c2-12. With respect to previous undertakings for the Net Billed Bonds, Energy Northwest has filed its annual financial information and operating data in a timely manner. On April 21, 2021, Energy Northwest filed a notice on EMMA that it extended the maturity of its Columbia Generating Station Electric Revenue Bond Anticipation Note, 2020C (Tax-Exempt) and 2020D (Taxable) by two months in November 2020, as permitted by the resolution authorizing the notes and the Loan Agreement dated May 1, 2020, between Wells Fargo Bank, National Association and Energy Northwest.

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 Energy Northwest. There have been several state initiatives involving energy issues, including one requiring certain electric utilities to obtain a percentage of their electricity from renewable resources.

BANKRUPTCY

A municipality such as Energy Northwest must be specifically authorized under state law to seek relief under Chapter 9 of the United States Bankruptcy Code (the "Bankruptcy Code"). Chapter 39.64 RCW, entitled the "Taxing District Relief Act," permits any "taxing district" (defined to include any municipality or political subdivision, such as Energy Northwest) to voluntarily petition for relief under the predecessor statute to the Bankruptcy Code. A creditor cannot bring an involuntary bankruptcy proceeding against a municipality, including Energy Northwest. Under Chapter 9, a federal bankruptcy court may not appoint a receiver for a municipality or order the dissolution or liquidation of the municipality. The federal bankruptcy courts have some discretionary powers under the Bankruptcy Code. Municipalities in the State, including Energy Northwest, are expressly authorized to carry out a plan of readjustment if approved by the appropriate court. Should Energy Northwest file for bankruptcy, there could be adverse effects on the holders of the Electric Revenue Bonds, including the Series 2025-A/B Bonds.

Under the Bankruptcy Code, if Energy Northwest became a debtor in a federal bankruptcy proceeding, the owners of the Electric Revenue Bonds would continue to have a statutory lien on revenues as described in "SECURITY FOR THE NET BILLED BONDS" after the commencement of the bankruptcy case so long as the revenues constitute "special revenues" within the meaning of the Bankruptcy Code. "Special revenues" are defined under the Bankruptcy Code to include, among other things, receipts by local governments from the ownership, operation or disposition of projects or systems that are primarily used to provide utility services. The Bankruptcy Code provides that "special revenues" can be applied to necessary operating expenses of the project or system before they are applied to other obligations. It is not clear which expenses would constitute necessary operating expenses.

If Energy Northwest is in bankruptcy, parties (including the Trustee and the holders of the Series 2025-A/B Bonds) may be prohibited from taking any action to collect any amount from Energy Northwest or to enforce any obligation of Energy Northwest, unless the permission of the bankruptcy court is obtained.

MISCELLANEOUS

The references, excerpts and summaries contained herein of the Electric Revenue Bond Resolutions, the Net Billing Agreements, the Columbia Project Agreement, the Assignment Agreements, the Post Termination Agreements and any other documents or agreements referred to herein do not purport to be complete statements of the provisions of such documents or agreements, and reference should be made to such documents or agreements for a full and complete statement of all matters relating to the Series 2025-A/B Bonds, the agreements securing the Series 2025-A/B Bonds and the rights and obligations of the holders thereof. Copies of the forms of the Electric Revenue Bond Resolutions, the Net Billing Agreements, the Columbia Project Agreement, the Assignment Agreements and the Post Termination Agreements and other reports, documents, agreements and studies referred to herein and in the Appendices hereto are available upon request at the office of Energy Northwest in Richland, Washington.

The authorizations, agreements and covenants of Energy Northwest are set forth in the Electric Revenue Bond Resolutions, and neither this Official Statement nor any advertisement of any Series of the Series 2025-A/B Bonds is to be construed as a contract with the holders of such Series 2025-A/B Bonds. Any statements made in this Official Statement involving matters of opinion or estimates, whether or not expressly so identified, are intended merely as such and not as representations of fact.

Bonneville has furnished the information herein relating to it.

APPENDIX A

BONNEVILLE POWER ADMINISTRATION

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APPENDIX A

BONNEVILLE POWER ADMINISTRATION

The information in this Appendix A has been furnished to Energy Northwest ("Energy Northwest" or the "Issuer") by Bonneville for use in the Official Statement, dated April 30, 2025, of the Issuer (the "Official Statement") with respect to its Project 1 Electric Revenue Refunding Bonds, Series 2025-A, Columbia Generating Station Electric Revenue and Refunding Bonds, Series 2025-A, Project 3 Electric Revenue Refunding Bonds, Series 2025-A, and Columbia Generating Station Electric Revenue Bonds, Series 2025-B (Taxable) (collectively the "Series 2025-A/B Bonds"). (Energy Northwest's Project 1, Columbia Generating Station and Project 3 are described in the Official Statement under "ENERGY NORTHWEST" and are referred to collectively in this Appendix A as part of the "Net Billed Projects." Bonds issued for the Net Billed Projects, including but not limited to the Series 2025-A/B Bonds, are referred to collectively in this Appendix A as "Net Billed Bonds.") Such information in this Appendix A is not to be construed as a representation by or on behalf of the Issuer or the Underwriters. The Issuer has not independently verified such information and is relying on Bonneville's representation that such information is accurate and complete. At or prior to the time of delivery of the Series 2025-A/B 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, does not contain any untrue statement of a material fact or omit to state any material fact necessary in order to make the statements in this Appendix A and in the Official Statement pertaining to Bonneville, in light of the circumstances under which they were made, not misleading.

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

This Appendix A contains financial information presented in accordance with accounting principles generally accepted in the United States of America ("GAAP") and certain non-GAAP financial metrics. For a discussion of the non-GAAP financial metrics used by Bonneville, see "BONNEVILLE FINANCIAL OPERATIONS—Bonneville's Use of Non-GAAP Financial Metrics." Certain tables where GAAP has not been applied are labeled as "unaudited." PricewaterhouseCoopers LLP, Bonneville's independent auditor, has not audited, reviewed, compiled, or applied agreed-upon procedures with respect to this information. Accordingly, PricewaterhouseCoopers LLP does not express an opinion or any form of assurance with respect to that financial data.

GENERAL

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

Bonneville's primary enabling legislation includes the following federal statutes: the Bonneville Project Act of 1937 (the "Project Act"); the Flood Control Act of 1944 (the "Flood Control Act"); Public Law 88-552 (the "Regional Preference Act"); the Federal Columbia River Transmission System Act of 1974 (the "Transmission System Act"); and the Northwest Electric Power Planning and Conservation Act of 1980 (the "Northwest Power Act"). Bonneville now markets electric power from 31 federal hydroelectric projects, most of which are located in the Columbia River basin and all of which are owned and operated either by the United States Army Corps of Engineers ("Corps") or the United States Bureau of Reclamation ("Reclamation"). Bonneville also has acquired on a long-term basis and markets power from several non-federally-owned and -operated projects, including an operating nuclear generating station (the "Columbia Generating Station") owned by Energy Northwest (a joint operating agency of Washington State) and having a rated capacity of approximately 1,207 megawatts. (Although the rated capacity of Columbia Generating

Station is 1,207 megawatts, Bonneville assumes 1,169 megawatts for long-range planning purposes.) In addition, firm energy from transfers, exchanges, and purchases comprise the remaining portion of Bonneville's electric power resources. Not taking into account estimated power lost through the transmission of electricity from generation sites to load sites ("transmission line losses"), Bonneville estimates that the foregoing projects and contracts have an expected aggregate energy output in Operating Year 2026 of approximately 9,617 annual average megawatts (defined below) under median water conditions and approximately 7,910 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 (non-leap year) year and each annual average megawatt is equal to 8,760 megawatt-hours.)

Bonneville sells, purchases, and exchanges firm power, seasonal surplus energy peaking capacity, and related power services. Bonneville also constructed, owns and/or possesses, operates, and maintains a high voltage transmission system (the "Federal Transmission System") comprising more than 15,000 circuit miles of high voltage transmission lines in the Pacific Northwest. Bonneville uses these transmission lines to deliver power to its power customers and makes transmission capacity available to other utilities, owners of generation projects, and power marketers. Bonneville's primary customer service area is the Pacific Northwest region of the United States, encompassing the states of Idaho, Oregon, and Washington, parts of western Montana, and small parts of western Wyoming, northern Nevada, northern Utah, and northern California (the "Pacific Northwest" or "Region"). Bonneville estimates that the population of the approximately 300,000 square-mile service area is approximately 15 million people. Electric power sold by Bonneville accounts for approximately 32 percent of the electric power generated in the Region.

Bonneville markets a large portion of this power to approximately 135 publicly-owned, cooperatively-owned, and tribal 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 company ("Direct Service Industrial Customer" or "DSI") located in the Region. Bonneville is also required by law to exchange power with qualifying utilities for resale to their residential and small farm electric power loads within the Region. The operation of this program, referred to as the "Residential Exchange Program," has resulted and is expected to continue to result in substantial payments by Bonneville to the exchanging utilities. The primary participants in the Residential Exchange Program have been and are investor-owned utilities in the Region (the "Regional IOUs"), of which there are six. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Residential Exchange Program."

Proportionately, Preference Customers are the largest customer group to which Bonneville sells power. For example, Bonneville estimated in Fiscal Year 2024 that, on a planning basis in Operating Year 2026, it will meet 7,743 annual average megawatts of loads, of which approximately 88 percent is forecast to be Preference Customer loads, approximately two percent is forecast to be Reclamation loads for irrigation pumping stations, approximately two percent is forecast to be non-Reclamation federal agency loads, less than one percent is forecast to be DSI loads, and approximately eight percent is forecast to be contract deliveries inside and outside the Region. (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.) 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—Federal System Load/Resource Balance."

The Transmission System Act placed Bonneville on a self-financing basis, meaning that Bonneville pays its costs from revenues it receives from the sale of power and the provision of transmission and other services, which Bonneville provides at rates that seek to produce revenues that recover Bonneville's costs, including certain payments to the United States of America, Department of Treasury (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 conformity with certain national regulatory initiatives to promote competition in wholesale power markets, in the 1990s Bonneville separated its power marketing function from its transmission system operation and electric system reliability functions. While Bonneville is a single legal entity, it conducts its business as two business units: "Power

Services" and "Transmission Services." See "TRANSMISSION SERVICES—FERC and Non-discriminatory Transmission Access and the Separation of Power Services and Transmission Services."

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

Bonneville makes certain payments to the United States Treasury. These payments are subject to the availability of net proceeds, which are gross cash receipts remaining in the Bonneville Fund after deducting all of the costs paid by Bonneville to operate and maintain the facilities of 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 (the "Federal System Hydroelectric Projects"), (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 Federal System Hydroelectric Projects, and (iv) costs allocated to irrigation projects as are required by law to be recovered from power sales. Bonneville met its scheduled payment responsibility to the United States Treasury of $792 million in full and on time for Bonneville's fiscal year ended September 30, 2024 ("Fiscal Year 2024"). 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 and its expenses may vary significantly from year to year. In order to accommodate such fluctuations in revenues and expenses and to assure that Bonneville has sufficient revenues to pay the costs necessary to maintain and operate the Federal System, all cash payment obligations of Bonneville including cash deficiency payments, if any, under the Net Billing Agreements, and cash payments, if any, under the 1989 Letter Agreement and the Direct Pay Agreements, and other operating and maintenance expenses, including lease rental payments for the transmission facilities and the costs of electric power conservation or generating resource acquisitions, have priority over payments by Bonneville to the United States Treasury. For a description of the Net Billing Agreements, the 1989 Letter Agreement, and the Direct Pay Agreements, see the Official Statement under the heading "SECURITY FOR THE NET-BILLED BONDS–Net Billing and Related Agreements." In the opinion of Bonneville's General Counsel, under federal statutes, Bonneville may make payments to the United States Treasury only from net proceeds; all other cash payments of Bonneville including cash deficiency payments, if any, under the Net Billing Agreements, and cash payments, if any, under the 1989 Letter Agreement and the Direct Pay Agreements, and other operating and maintenance expenses, have priority over payments by Bonneville to the United States Treasury for the costs described in (i) through (iv) in the preceding paragraph. See the Official Statement under the heading "SECURITY FOR THE NET BILLED BONDS" and "BONNEVILLE FINANCIAL OPERATIONS—Order in Which Bonneville's Costs Are Met."

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

Regional Power Sales and Rates

Current Long-Term Preference Contracts

Bonneville's current power sales agreements with Preference Customers are in effect through Fiscal Year 2028 ("Long-Term Preference Contracts"). Virtually all such agreements were executed in 2008 and relate to power sales from Fiscal Year 2012 through Fiscal Year 2028. Under these contracts, Bonneville provides various electric power products primarily to meet the related Preference Customers' own "net requirements" in the Region. Net requirements are the customers' native loads (retail loads within their respective service territories) net of non-Federal System generating resources, if any, designated by a related customer as being used to serve its native loads. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Bonneville's Obligation to Meet Certain Firm Power Requirements in the Region—Long-Term Preference Contracts, Federal Agency Sales, and Related Power Products."

Bonneville sells electric power for Regional load requirements at rates that are established to recover Bonneville's cost of providing such service. Bonneville sells power to Preference Customers and federal agencies, in each case for their requirements, at periodically established "Priority Firm Power Rates" (referred to herein as "PF Preference Rates") that are proposed in advance of the delivery of the power. The PF Preference Rate class is Bonneville's lowest-cost, statutorily-designated, power rate class. PF Preference Rates include separate rate schedules for specific types of service provided to Preference Customers and federal agencies, and the related rate levels vary depending on the costs of providing such services. Beginning in Fiscal Year 2012, PF Preference Rates have been established, and at least through the term of the Long-Term Preference Contracts will be established, on the basis of "Tiered Rates," as discussed below. "Tier 1 PF Rates" apply to a very large portion of the power sales Bonneville makes to Preference Customers, and "Tier 2 PF Rates" apply to a small portion of the power sales Bonneville makes to Preference Customers, essentially for incremental loads above power sold at Tier 1 PF Rates. 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." For a discussion of Bonneville's currently applicable power rates, see "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Current Bonneville Power and Transmission Rates" and "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Power Rates for Fiscal Years 2024-2025." The rate for most of the power Bonneville has historically sold to DSIs is the Industrial Firm Power Rate ("IP Rate"), which is based on the PF Preference Rate and certain adjustments required by federal law.

Long-Term Preference Contracts Beginning in Fiscal Year 2029

In anticipation of the expiration of the Long-Term Preference Contracts and other agreements at the end of Fiscal Year 2028, Bonneville has been engaging its customers through a public process to determine the character of Bonneville's long-term power sales commitments in the Region and Bonneville's long-term role in meeting Regional power needs beginning in Fiscal Year 2029. In Fiscal Year 2023, Bonneville held public workshops to discuss key issues and proposals. In July 2023, Bonneville released a draft policy that reflected the types of products and services that Bonneville plans to offer under new long-term power sales contracts. After taking public comment on the draft policy, Bonneville released a final policy and record of decision on March 21, 2024. This policy informed the policy implementation and contract development stage which began in April 2024 and concluded in February 2025. Draft contract templates were released for public comment on March 12, 2025, with final contract templates expected to be released in June 2025. Bonneville will continue to establish PF Preference Rates on the basis of tiered rates and is conducting a parallel process in Fiscal Year 2024 and Fiscal Year 2025 to develop the rate methodology that will be applicable to the new long-term power sales contracts (referred to as the "Public Rate Design Methodology"). The Public Rate Design Methodology will go into effect beginning in Fiscal Year 2029 and will guide how Bonneville will allocate costs and establish rates under the new power sales contracts. Bonneville expects to execute new long-term power sales contracts and other agreements by the end of December 2025. The new power sales contracts will be 19-year contracts with 16 years of power deliveries in Fiscal Year 2029 through Fiscal Year 2044.

Bonneville will offer similar products and services under the Long-Term Preference Contracts beginning in Fiscal Year 2029 as compared to the current Long-Term Preference Contracts. Bonneville has proposed new flexibilities to allow for customers to add non-federal resources providing customers more opportunities to develop and integrate non-federal resources. The Long-Term Preference Contracts address emerging markets, like day-ahead markets and evolving resource adequacy program requirements, with flexibility by proposing limited and focused future public processes and subsequent contract updates over the term of the contract.

CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE

Fiscal Year 2024 Financial Results

In Fiscal Year 2024, Bonneville made its scheduled United States Treasury payments on time and in full for the 41st consecutive year. Bonneville recorded negative net revenues in Fiscal Year 2024 of $132 million, an increase of approximately $125 million over the prior fiscal year negative net revenues of $257 million. The increase in Fiscal Year 2024 year-end agency net revenues is primarily due to the year-over-year difference in the Power Reserves Distribution Clause rate reductions that were applied as a credit to Power rates in Fiscal Year 2023 and in Fiscal Year 2024. For additional details related to Fiscal Year 2024 financial results, see "BONNEVILLE FINANCIAL OPERATIONS—Management's Discussion of Operating Results—Fiscal Year 2024." Bonneville finished Fiscal Year 2024 with Total Financial Reserves (as hereinafter defined) of approximately $1.3 billion (Power Services' Total Financial Reserves of $591 million and Transmission Services' Total Financial Reserves of $707 million), which is a decrease of approximately $429 million, or 25 percent less than the prior fiscal year. "Total Financial Reserves" is an unaudited metric that is not in accordance with GAAP. Bonneville management believes that the use and reporting of Total Financial Reserves assists in reflecting the financial reserves Bonneville has on hand to meet payment obligations. Bonneville relies on a financial metric it refers to as Reserves Available for Risk ("RAR") as a measure of accumulated cash flow derived from operations. Bonneville divides RAR into "Transmission Services' RAR" and "Power Services' RAR," each of which measures the share of RAR derived from the respective business line's operations. While the RAR metric is not a measure in accordance with GAAP and is unaudited, Bonneville management nonetheless believes that the RAR metric provides a sound measure of Bonneville's reserves derived (and retained) from operations. For a discussion of the non-GAAP financial metrics used by Bonneville, see "BONNEVILLE FINANCIAL OPERATIONS—Bonneville's Use of Non-GAAP Financial Metrics."

Bonneville finished Fiscal Year 2024 with RAR of approximately $823 million (Power Services' RAR of approximately $507 million and Transmission Services' RAR of approximately $316 million), a decrease of $463 million, or approximately 36 percent from the prior year. The decrease in Fiscal Year 2024 year-end agency RAR is primarily due to: (i) implementation of the Fiscal Year 2024 Reserves Distribution Clauses that triggered for Power Services and Transmission Services, which resulted in a $325 million planned decrease in RAR and (ii) significant purchased power expense that was incurred in Fiscal Year 2024 over amounts forecast when establishing rates for this period. The year-end RAR balance is equivalent to the amount of cash needed to meet operating expenses for 116 days. Bonneville measures its "Days Cash On Hand" using the following equation: (i) RAR divided by (ii) Operating Expenses (as defined in the 2022 Financial Plan) divided by 365. For additional details regarding Bonneville's policies related to financial resiliency, see "BONNEVILLE FINANCIAL OPERATIONS—Internal Guidance Affecting Bonneville Financial Operations"). For additional details related to Fiscal Year 2024 financial results, see "BONNEVILLE FINANCIAL OPERATIONS—Management's Discussion of Operating Results—Fiscal Year 2024." Based on the Fiscal Year 2024 year-end Power Services and Transmission Services RAR balances, a rate mechanism referred to as the Reserves Distribution Clause (as hereinafter defined) has triggered for application to Transmission Services. See "TRANSMISSION SERVICES—General—Bonneville's Transmission and Ancillary and Control Area Services Rates."

Fiscal Year 2025 Expectations

The forward-looking financial information included in this Fiscal Year 2025 Expectations section was not prepared with a view toward compliance with the guidelines of the Securities and Exchange Commission or the guidelines established by the American Institute of Certified Public Accountants for preparation or presentation of prospective financial information.

This forward-looking financial information included in this Fiscal Year 2025 Expectations section has been prepared by, and is the responsibility of, Bonneville's management. PricewaterhouseCoopers LLP has not audited, reviewed, examined, compiled nor applied agreed-upon procedures with respect to the accompanying forward-looking financial information included in this Fiscal Year 2025 Expectations section and, accordingly, PricewaterhouseCoopers LLP does not express an opinion or any other form of assurance with respect thereto. The PricewaterhouseCoopers LLP report included in this document (Appendix B-1 to the Official Statement) relates to Bonneville's previously issued financial statements. It does not extend to the forward-looking financial information included in this Fiscal Year 2025 Expectations section and should not be read to do so.

As of February 13, 2025, Bonneville forecast that it would finish Fiscal Year 2025 with RAR of $460 million (Power Services' RAR of $289 million and Transmission Services' RAR of $171 million), or approximately $363 million less than the $823 million RAR as measured as of the end of Fiscal Year 2024. The forecast decrease in Fiscal Year 2025 RAR is primarily attributable to: (i) the Transmission Reserves Distribution Clause that triggered for application to Fiscal Year 2025 rates, which includes an $83 million planned decrease in RAR for debt reduction (see "—Current

Bonneville Power and Transmission Rates") and (ii) significant purchased power expense that has been incurred over amounts forecast when establishing rates for this period. If Bonneville's RAR levels fall below an established threshold, certain rate level adjustment mechanisms are available to increase power or transmission rates and revenues in Fiscal Year 2025. The forecast Fiscal Year 2025 year-end RAR amount is in the range of possibly triggering a Financial Reserves Policy Surcharge (as defined below) for application to Power Rates in Fiscal Year 2026. For more details, see "—Current Bonneville Power and Transmission Rates."

Forecasts of fiscal year-end results are based on numerous uncertain variables, including but not limited to hydroelectric and water conditions and the level and volatility of market prices for electric power, and are subject to change.

Based on Total Financial Reserves levels and forecasts of revenues and expenses and liquidity tools available, Bonneville believes that it will meet its Fiscal Year 2025 United States Treasury payment obligation on time and in full.

Current Bonneville Power and Transmission Rates

To establish rates of general applicability for electric power and for transmission and related services, on July 28, 2023, Bonneville filed final proposed electric power and transmission rates for Fiscal Year 2024 and Fiscal Year 2025 (the "2024-2025 Rate Period") with FERC for its review. FERC granted final confirmation and approval of such rates in March 2024. The rates approved by FERC are referred to herein as the "Final 2024-2025 Rates."

The Final 2024-2025 Rates reflect a decrease in power base rates on average and an increase in transmission rates over rates in the immediately preceding two-year rate period (the "2022-2023 Rate Period"). Average Tier 1 PF Rates decreased by less than 1 percent, to $34.69 per megawatt hour, and the average Tier 2 PF Rates increased by 83 percent, to $61.50 when compared to Average Tier 1 and 2 PF Rates in effect in the prior rate period. For more details regarding the average Tier 2 PF Rate increase, 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—Comparison of Tier 1 PF Rates and Tier 2 PF Rates." There was no change in the weighted average transmission rates, when compared to average rates in effect in the prior rate period. See "TRANSMISSION SERVICES—General—Bonneville's Transmission and Ancillary and Control Area Services Rates." These rates are exclusive of other surcharges discussed below.

Certain rate level adjustments for both power and transmission and related rates (referred to herein as the Power Services or Transmission Services "Cost Recovery Adjustment Clause" or "CRAC") and the Financial Reserves Policy Surcharge (the "Financial Reserves Policy Surcharge" or "FRP Surcharge") included in the Final 2024-2025 Rates did not trigger for application to Fiscal Year 2024 or Fiscal Year 2025 power or transmission rate levels; however, a rate mechanism referred to as the "Reserves Distribution Clause" or "RDC" has triggered for application to Power Services and Transmission Services Fiscal Year 2024 rates and to Transmission Services for Fiscal Year 2025 rates. An RDC is based on RAR level thresholds by business line at September 30 and, if RAR levels exceed 120 Days Cash On Hand, could result in a decision to decrease certain Power Services or Transmission Services rates in either year of the rate period or amounts could be retained by Bonneville for other certain purposes. The portions of the Power RDC and Transmission RDC that resulted in rate reductions implemented in Fiscal Year 2024, as described below, had the effect of reducing Bonneville's net revenues in Fiscal Year 2024.

On September 30, 2023, Power Services' RAR were $923 million and the total RAR were $1.3 billion, resulting in a Power RDC triggering in the amount of $285 million for application to certain Power Services rate levels in Fiscal Year 2024 (the "Fiscal Year 2023 Power RDC"). The Administrator determined that $165 million of the Fiscal Year 2023 Power RDC would be applied to reduce Power rates from December 2023 through September 2024. Credits of $165 million were applied to power customer bills through September 2024. In addition to the rate reduction applied in Fiscal Year 2024, $90 million of the Fiscal Year 2023 Power RDC amount was held in Total Financial Reserves for debt reduction in Fiscal Year 2024; however, it was ultimately retained and instead used to support Bonneville's liquidity at the end of Fiscal Year 2024. The remaining $30 million of the Fiscal Year 2023 Power RDC set aside to fund certain fish and wildlife expenses on an accelerated basis (in advance of when such expenditures were originally expected to be made) is being held in Reserves Not Available For Risk ("RNAR") until such expenditures are disbursed. RNAR is a non-GAAP financial metric Bonneville uses as a measure of accumulated financial reserves that are not available for risk mitigation when establishing rates since such amounts are already committed for the payment of certain expenses. The Fiscal Year 2023 Power RDC is being challenged in court. See "BONNEVILLE LITIGATION— Fiscal Year 2023 Power RDC Challenge."

On September 30, 2023, Transmission Services' RAR were $363 million and the total RAR were $1.3 billion, resulting in a Transmission RDC triggering in the amount of $130 million for application to certain Transmission Services rate levels in Fiscal Year 2024. The Administrator determined that $50 million of the Transmission RDC would be retained in Total Financial Reserves to fund costs to be incurred in Fiscal Year 2024 above amounts forecast when establishing rates for the current period and $80 million would be held in Total Financial Reserves for debt reduction in Fiscal Year 2024 (either for early payment of debt or revenue financing of capital expenditures, with any unused amount at the end of Fiscal Year 2024 becoming available to support Bonneville's liquidity). Such amounts were applied to Transmission costs and for debt reduction in Fiscal Year 2024.

On September 30, 2024, Power Services' RAR were $507 million and the total RAR were $823 million. An RDC was not triggered for application to Power Services rates in Fiscal Year 2025.

On September 30, 2024, Transmission Services' RAR were $316 million and the total RAR were $823 million, resulting in a Transmission RDC triggering in the amount of $83 million. The Administrator determined that $83 million would be held in Total Financial Reserves for debt reduction in Fiscal Year 2025 (either for early repayment of debt or revenue financing of capital expenditures, with any unused amount at the end of Fiscal Year 2025 becoming available to support Bonneville's liquidity).

For other details related to the Final 2024-2025 Rates, see "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Power Rates for Fiscal Years 2024-2025" and "TRANSMISSION SERVICES—General—Bonneville's Transmission and Ancillary and Control Area Services Rates."

Proposed Bonneville Power and Transmission Rates for Fiscal Years 2026-2028

Bonneville began conducting workshops in the spring of 2024 related to developing rates for power and for transmission and related services for Fiscal Years 2026, 2027 and 2028 (the "2026-2028 Rate Period"). On November 22, 2024, Bonneville issued its initial rate proposal for the 2026-2028 Rate Period ("the 2026-2028 Initial Rate Proposal"), which began an administrative process that will culminate in a final rate proposal for the 2026-2028 Rate Period (the "2026-2028 Final Rate Proposal") and a record of decision. Bonneville expects to submit the final rate proposal to FERC by the end of July 2025. In order to align the rate period with expiration of the Long-Term Preference Contracts on September 30, 2028, Bonneville has determined that it will implement a single three-year rate period for Power Services and Transmission Services rates for the next rate period.

Consistent with longstanding policy, the 2026-2028 Initial Rate Proposal was prepared to assure payment of all costs and provide at least a 92.65 percent probability (92.6 percent is the three-year equivalent to the long-standing 95 percent probably used for a two-year rate period) over the three-year rate period that Bonneville will make its scheduled payments to the United States Treasury on time and in full. (Bonneville refers to this probability as "Treasury Payment Probability" or "TPP.") In determining TPP, Bonneville relies on numerous factors including estimates and forecasts of costs, risks and revenues, the ability to increase rate levels on short notice under the CRAC or Financial Reserves Policy Surcharge (hereinafter described), the availability of short-term financial liquidity tools, and RAR. See "BONNEVILLE FINANCIAL OPERATIONS—Bonneville's Use of Non-GAAP Financial Metrics." Bonneville's United States Treasury payments are payable after Bonneville's non-federal payment obligations such as payments under the Net Billing Agreements, the 1989 Letter Agreement, and the Direct Pay Agreements. See "BONNEVILLE FINANCIAL OPERATIONS—Order in Which Bonneville's Costs Are Met."

Proposed Power Services Rate Increase

Based on the 2026-2028 Initial Rate Proposal, on November 22, 2024, Bonneville estimated that average Tier 1 PF Rates would be $38.44 per megawatt hour in the rate period, an increase of approximately 10.8 percent from the average Tier 1 PF Rates currently in effect. In its 2026-2028 Initial Power Rate Proposal, Bonneville has proposed an average of $42 million per year of revenue financing in each of the three fiscal years of the rate period for funding a portion of Power Services capital investments. Bonneville also forecast that average Tier 2 PF Rates would be

$68.51, an 11.4 percent increase over the average Tier 2 PF Rates currently in effect. For more details regarding the proposed average Tier 2 PF Rate increase, see "—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Bonneville's Obligation to Meet Certain Firm Power Requirements in the Region—Comparison of Tier 1 PF Rates and Tier 2 PF Rates."

Proposed Transmission Services Rate Increase

Based on the 2026-2028 Initial Rate Proposal, released on November 22, 2024, Bonneville estimated that transmission and related rates would increase by approximately 24 percent over the rates currently in effect. The upward pressure on transmission rates arises primarily from increased revenue financing ($125 million in each of the three fiscal years of the rate period) for funding a portion of Transmission capital investments, inflationary pressures, and forecast increased costs related to grid modernization and expansion to enhance optimization and reliability of the grid. See "BONNEVILLE FINANCIAL OPERATIONS—Bonneville's Capital Program."

Proposed Cost Recovery Adjustment Clause and Related Rate Level Adjustment

In the 2026-2028 Initial Rate Proposal, Bonneville has proposed to continue use of a rate level adjustment mechanism for power and transmission and related rates (referred to herein as the "Cost Recovery Adjustment Clause" or "CRAC"). The CRAC mechanisms proposed in the 2026-2028 Initial Rate Proposal are similar to the CRAC for rates currently in effect. An increase in power or transmission and related rate levels under the proposed CRAC would occur if certain financial information resulted in Power Services' or Transmission Services' expenses that were higher and/or revenues that were lower than anticipated that resulted in Power Services' or Transmission Services' RAR falling below certain thresholds as of September 30.

As proposed in the 2026-2028 Initial Rate Proposal, the CRAC would enable Bonneville to increase certain power and related rate levels over base rates to obtain up to $300 million in additional revenue and would enable Bonneville to increase certain transmission and related rate levels over base rates to obtain up to $100 million of additional revenue in each of the three fiscal years of the rate period, without a time consuming rate proceeding, if Power Services' or Transmission Services' RAR are below zero at the beginning of each of the three fiscal years in the rate period. The amount of additional revenue to be obtained under the CRAC in a fiscal year would be established, in general, to be the amount of the difference between zero and the Power Services' or Transmission Services' RAR at the beginning of the fiscal year in which the CRAC is evaluated for implementation (this differential is referred to herein as the "CRAC Underrun"). For calculation of the CRAC amount, the CRAC Underrun is reduced by the amount of planned revenue financing, if any, for such fiscal year. More particularly, the CRAC would be used to obtain in a fiscal year: (i) all of the first $100 million of a Power or Transmission CRAC Underrun, if any, for such fiscal year, and (ii) one half of any remaining Power CRAC Underrun for such fiscal year, up to a maximum of $200 million. This would result in an annual maximum Power CRAC of $300 million and an annual maximum Transmission CRAC of $100 million. The CRAC terms include a *de minimis* provision under which Bonneville would not trigger the CRAC for implementation for a fiscal year unless the CRAC Underrun were to exceed $5 million.

The Power Services' or Transmission Services' beginning RAR balance is determined using the financial results of the Federal System for the prior fiscal year that become available each November. Thus, if Power Services' or Transmission Services' RAR were below zero at September 30, 2025, then Bonneville would (subject to a *de minimi*s exception described above) increase power or transmission and related rate levels in December 2025 through September 2026 to obtain additional revenues in Fiscal Year 2026. Likewise, if Power Services' or Transmission Services' RAR were below zero at September 30, 2026, then Bonneville would (subject to a *de minimi*s exception described above) increase power or transmission and related rate levels in December 2026 through September 2027 to obtain additional revenues in Fiscal Year 2026. Likewise, if Power Services' or Transmission Services' RAR were below zero at September 30, 2027, then Bonneville would (subject to a *de minimi*s exception described above) increase power or transmission and related rate levels in December 2027 through September 2028 to obtain additional revenues in Fiscal Year 2028. If a Power or Transmission CRAC were to trigger for application to Fiscal Year 2026 power or transmission and related rate levels, Bonneville would notify customers by November 30, 2025.

Proposed Financial Reserves Policy Surcharge

As proposed in the 2026-2028 Initial Rate Proposal, Power and Transmission Services rates continue to make available a surcharge rate adjustment mechanism (the "Financial Reserves Policy Surcharge" or "FRP Surcharge") to implement Bonneville's Financial Reserves Policy and rate actions to raise RAR levels when they fall below a specified level for each business line. An increase in Power Services or Transmission Services rate levels under the Financial Reserves Policy Surcharge would occur if Power Services' or Transmission Services' RAR fall below certain thresholds as of September 30. The thresholds for each business line are equivalent to the amount of cash needed to meet operating expenses for 60 days. For Power Services, the forecast amount of cash expected to be needed to meet its operating expenses for 60 days is $373 million. For Transmission Services, the forecast amount of cash expected to be needed to meet its operating expenses for 60 days is $151 million. As proposed in the 2026-2028 Initial Rate Proposal, the Financial Reserves Policy Surcharge would allow Bonneville to increase certain power and related rates over base rates to obtain up to $40 million of additional revenue in each of the three fiscal years of the rate period if Power Services' RAR were below $373 million at September 30, 2025, September 30, 2026, or September 30, 2027. In addition, the Financial Reserves Policy Surcharge would allow Bonneville to increase certain transmission and related rate levels over base rates to obtain up to $15 million of additional revenue in each of the three fiscal years of the rate period if Transmission Services' RAR were to fall below $151 million at September 30, 2025, September 30, 2026, or September 30, 2027. As with the Power and Transmission CRAC, the FRP Surcharge thresholds are first reduced by the amount of planned revenue financing, if any, for such fiscal year before determining the surcharge amount. The FRP Surcharge terms also include a *de minimis* provision under which Bonneville would not trigger the Surcharge for implementation for a fiscal year unless the surcharge underrun were to exceed $5 million. If a Financial Reserves Policy Surcharge were to trigger for application to Fiscal Year 2026 power or transmission rate levels, Bonneville would notify customers by November 30, 2025 and increase power or transmission rate levels to obtain additional revenues in December 2025 through September 2026.

In addition to the CRAC and FRP Surcharge mechanisms that are similar to such mechanisms in the 2024-2025 Rate Period, under the 2026-2028 Initial Rate Proposal, Bonneville reserves the ability to institute another expedited rate case proceeding and increase rates or rate levels in the rate period, which Bonneville has estimated would take up to six months.

Proposed Reserves Distribution Clause

As proposed in the 2026-2028 Initial Rate Proposal, the Power Services and Transmission Services rates continue the availability of the RDC. The RDC is based on RAR level thresholds by business line at September 30 (subject to a *de minimi*s exception described below) and could result in a decision to decrease certain Power Services or Transmission Services rates in each year of the rate period or amounts could be retained by Bonneville for the purposes described below. In order to trigger a distribution under the Reserves Distribution Clause, Power Services' RAR or Transmission Services' RAR must exceed its 120 Days Cash on Hand target ($746 million for Power Services or $302 million for Transmission Services). In addition, from an agency perspective, the total RAR must be at least $786 million, in the aggregate, which is the forecast amount of cash expected to be needed to meet the agency's operating expenses for at least 90 days. The RDC terms include a *de minimis* provision under which Bonneville would not trigger an RDC for implementation for a fiscal year unless the business line RAR were to exceed its 120 Days Cash on Hand target by $5 million.

Uncertainty Regarding Proposed Rates and Rate Levels

The terms of the 2026-2028 Final Rate Proposal, including but not limited to the terms of base Power Services and Transmission Services rates, and the terms of a Power or Transmission CRAC, Power or Transmission Financial Reserves Policy Surcharge, or Power or Transmission RDC, if any, could differ from those included in the 2026-2028 Initial Rate Proposal. Bonneville's expectations of rate levels for the 2026-2028 Rate Period and the likelihood that a Power or Transmission CRAC, Power or Transmission Financial Reserves Policy Surcharge, or Power or Transmission RDC, if any, would trigger in any year of the three year rate period are subject to change based on numerous factors including Bonneville's financial performance in Fiscal Year 2025 and the terms of the 2026-2028 Final Rate Proposal.

Developments Relating to the Endangered Species Act

The operation of the Federal System Hydroelectric Projects by the Corps, Reclamation and Bonneville (also referred to as the "Action Agencies") is subject to the Endangered Species Act ("ESA"). The listing under the ESA of certain anadromous and other native fish species that inhabit the Columbia River and its tributaries has led to the preparation of a series of biological opinions for operation and maintenance of Federal System Hydroelectric Projects on the Columbia and Snake Rivers. Beginning in the early 1990s, the National Oceanic and Atmospheric Administration's National Marine Fisheries Service ("NOAA Fisheries") has issued a succession of biological opinions relating to listed anadromous salmonid species of the Columbia and Snake Rivers. In 2000, the United States of America, Department of Interior, Fish and Wildlife Service ("Fish and Wildlife Service") issued a separate biological opinion regarding ESA-listed bull trout in the Columbia Basin and white sturgeon in the Kootenai River. Because hydropower dam operations in Montana and Idaho affect the listed sturgeon and bull trout as well as the salmonid species covered by the NOAA Fisheries biological opinions, NOAA Fisheries and the Fish and Wildlife Service coordinate their biological opinions regarding hydropower operations. Environmental Impact Statements related to the Federal System Hydroelectric Projects reflect both the NOAA Fisheries' and the Fish and Wildlife Service's biological opinions. Each of the NOAA Fisheries biological opinions from 1993 on has been the subject of litigation and judicial review and has resulted in court orders remanding biological opinions, including NOAA Fisheries' biological opinion for the Columbia and Snake Rivers issued in 2014 (referred to herein as the "2014 Columbia River System Supplemental Biological Opinion"). See "POWER SERVICES—Certain Statutes and other Matters Affecting Bonneville's Power Services—Fish and Wildlife—The Endangered Species Act" and "BONNEVILLE LITIGATION—Columbia River ESA Litigation."

In 2016, the United States District Court for the District of Oregon ("District Court") concluded that the Corps and Reclamation violated the National Environmental Policy Act ("NEPA") and identified a number of deficiencies with the 2014 Columbia River System Supplemental Biological Opinion. The District Court issued an order directing that a new environmental impact statement related to the Columbia River System Operations ("CRSO") be prepared and that a new biological opinion be issued based on findings in the CRSO environmental impact statement to support adoption and implementation of the proposed action consulted upon in the biological opinions. A related case pending in the United States Court of Appeals for the Ninth Circuit ("Ninth Circuit Court") was stayed pending the outcome of the District Court case. For more details related to this case, see "BONNEVILLE LITIGATION—Columbia River ESA Litigation."

In 2020, the Action Agencies issued a draft CRSO Environmental Impact Statement (the "Draft CRSO EIS") followed by a Final CRSO Environmental Impact Statement (the "Final CRSO EIS") on July 31, 2020. The Final CRSO EIS responded to substantive comments on the Draft CRSO EIS, described the Action Agencies' Preferred Alternative (the "Preferred Alternative"), and included, as appendices, the NOAA Fisheries' biological opinion for the Columbia and Snake Rivers issued in 2020 (referred to herein as the "2020 NOAA Fisheries Columbia River System Biological Opinion") and the Fish and Wildlife Service's biological opinion for the Columbia and Snake Rivers issued in 2020 (referred to herein as the "2020 Fish and Wildlife Service Columbia River System Biological Opinion) (collectively, the "2020 Columbia River System Biological Opinions") that evaluate impacts of the Preferred Alternative. Despite initial estimates in the Draft CRSO EIS of potential upward rate pressure of up to 2.7 percent on power rates when compared to the "No Action Alternative" (which is based on the 2016 system operation rules), subsequent changes in other rate drivers allowed Bonneville to recover its costs while proposing an average power rate decrease in the Final 2022-2023 Rates from the average power rates in effect in the prior period.

Various plaintiffs have filed complaints in the Ninth Circuit Court and District Court challenging the joint record of decision by the Action Agencies adopting the Final CRSO EIS and 2020 Columbia River System Biological Opinions alleging that Action Agencies' decision violated certain provisions of the ESA, NEPA, the Administrative Procedures Act ("APA"), and the Northwest Power Act. Bonneville's part in that record of decision was challenged by three petitioners in the Ninth Circuit Court. These challenges were consolidated on January 13, 2021. There is substantial overlap between the Ninth Circuit Court and District Court cases.

In October 2021, the Biden Administration announced a short-term agreement on the operation of the Federal System Hydroelectric Projects. The agreement paused litigation on the selected alternative in the CRSO EIS Record of Decision and associated ESA consultations.

As part of mediated discussions related to the CRSO EIS, on September 21, 2023, Bonneville and other agencies and departments within the U.S. Government entered into a memorandum of understanding and settlement agreement with the Confederated Tribes of the Colville Reservation, the Coeur d'Alene Tribe, and the Spokane Tribe of Indians ("P2IP Tribes"). In exchange for a 20 year pause in the CRSO EIS litigation in which the P2IP Tribes challenged the Action Agencies' adoption of the CRSO EIS and associated ESA consultations, Bonneville will make available to the P2IP Tribes a total of $10 million per year from Fiscal Year 2024 – Fiscal Year 2043, adjusted each year for inflation, for a total of $200 million plus adjustments for inflation for implementation of the Phase 2 Implementation Plan ("P2IP") projects for reintroducing specific non-federally protected salmonid stocks above Chief Joseph and Grand Coulee dams in the upper Columbia River Basin.

On October 30, 2023, the remaining parties gave notice they would not seek to revive the litigation through December 15, 2023, to allow for continued mediation discussions. On December 14, 2023, the Biden Administration announced the *U.S. Government Commitments in Support of the Columbia Basin Restoration Initiative and in Partnership with the Six Sovereigns* and associated Memorandum of Understanding (the "December 2023 Agreement"), an agreement to work in partnership with Pacific Northwest Tribes and States to further the restoration of native fish populations, expand Tribally sponsored clean energy production, and provide stability for communities that depend on the Columbia River System. Under the December 2023 Agreement, the Six Sovereigns (the Confederated Tribes and Bands of the Yakama Nation, the Confederated Tribes of the Umatilla Indian Reservation, the Confederated Tribes of the Warm Springs Reservation of Oregon, the Nez Perce Tribe, the State of Oregon, and the State of Washington) agreed to a stay of the CRSO EIS litigation in exchange for Bonneville's commitment to make available $200 million over 10 years to the U.S. Fish and Wildlife Service for Lower Snake River Compensation Plan hatchery modernization, upgrades and maintenance; plus an additional $100 million over 10 years for projects that contribute to the restoration of salmon and other native fish populations, as guided by the Six Sovereigns. This agreement concludes the mediation and on February 8, 2024, the U.S. District Court for the District of Oregon granted a stay through December 13, 2028 (with potential for an additional five years), and on February 23, 2024, the U.S. Court of Appeals for the Ninth Circuit dismissed without prejudice litigation regarding the CRSO EIS and associated ESA consultations. The litigation stays are conditioned on the U.S. Government meeting its obligations under the December 2023 Agreement. The signatories to the agreement that gave rise to the motions for stay and dismissal are now implementing the commitments in the agreement. The signatories submitted a Joint Annual Report to the District Court on January 14, 2025, in accordance with the December 2023 Agreement.

On December 18, 2024, the Corps and Reclamation issued a Notice of Intent ("NOI") to Supplement the CRSO EIS ("SEIS"). This NOI started the scoping period for the SEIS, which invites all affected federal, state, and local agencies, tribes, other interested parties, and the public to participate in the NEPA process during development of the SEIS. The scoping period was expected to end on May 9, 2025; however, the Corps and Reclamation rescinded the NOI and are expected to issue a new NOI in the coming weeks. The scope of the new NOI is unknown at this time. For the ESA consultations associated with the CRSO EIS, the Action Agencies have reinitiated consultation with the U.S. Fish and Wildlife Service due to recent listings and proposed listings of species. The Action Agencies are evaluating whether reinitiation of ESA consultation with NOAA Fisheries is necessary. Bonneville is unable to predict the outcome of the SEIS or its potential impact on the 2020 Columbia River Biological Opinions.

For a more detailed discussion of the challenges to the 2020 Columbia River System Biological Opinions and Final CRSO EIS, see "BONNEVILLE LITIGATION—Columbia River ESA Litigation."

Costs related to both the P2IP and December 2023 Agreement will be funded through power rates as applied to Bonneville's power customers. The Parties are working on implementation of both agreements.

Bonneville's funding commitments are directed at specific actions as described in the P2IP or the December 2023 Agreement. None of those actions include studies or projects that would further dam breaching. It is the opinion of the General Counsel of Bonneville that breaching or other similar major structural changes at any of the dams of the Federal System would require Congressional enactment authorizing such action.

In August 2021, the plaintiffs requested settlement discussions regarding short-term fish passage operations for 2022. Based on the settlement reached by the parties regarding spill for the 2022 fish passage season (approximately April-June 2022) at eight federal Columbia River System dams, both cases were stayed through July 2022. The litigation stay was extended until August 31, 2023, at the District Court and until September 8, 2023, in the Ninth Circuit Court.

Under the December 2023 Agreement, the spill for the 2025 fish passage season (approximately April-June 2025) at the Snake River and Columbia River Federal System dams is similar to the effects of the spill for the recent fish passage seasons. For a more detailed discussion of the challenges to the 2020 Columbia River System Biological Opinions and Final CRSO EIS, see "BONNEVILLE LITIGATION—Columbia River ESA Litigation."

There are three consolidated petitions currently filed with the Ninth Circuit Court challenging Bonneville's authority to sign on to the December 2023 Agreement. This matter is in administrative closure through June 2, 2025 while the parties participate in mediation. Bonneville is unable to predict the outcome of this litigation or its potential impact on the December 2023 Agreement and associated spill operations.

Change in Administration

On January 20, 2025, Donald J. Trump was sworn in as President of the United States of America. On February 4, 2025, Chris Wright was sworn in as the Secretary of the United States Department of Energy.

With every new Administration, national policy objectives may change and shifting political priorities could impact Bonneville. On January 20, 2025, President Trump issued a Presidential Memorandum instituting a federal hiring freeze intended to be replaced by a long-term workforce reduction plan to be developed by the United States Office of Personnel Management ("OPM"). On February 26, 2025, the United States Office of Management and Budget ("OMB"), together with OPM, released further guidance for agencies to prepare for large-scale reductions in force. Bonneville is working with DOE, OPM and OMB to determine how to carry out the order. As a result of the hiring freeze, Bonneville rescinded approximately 90 job offers.

On January 28, 2025, Bonneville employees received the "Fork in the Road" email from OPM offering a Deferred Resignation Program ("DRP") and voluntary early retirement for those that qualify. The DRP enabled employees to resign effective September 30, 2025 (or December 31, 2025, if retiring), but be placed on administrative leave beginning as early as the first week of February until the September resignation date or December retirement date. Bonneville lost approximately 225 employees to the DRP. Additionally, in mid-February, all federal agencies, including Bonneville, were required to lay off employees in their one or two year probationary period. Of Bonneville's approximately 400 probationary employees, 89 were terminated on February 13, 2025. In total, Bonneville has lost approximately 310 employees through rescinded offers, resignations, early retirements, and layoffs, reducing total full-time equivalent employees from approximately 3,500 to approximately 3,100 full-time equivalent employees as of March 1, 2025. On March 6, 2025, Bonneville was able to re-hire probationary period employees who were terminated on February 13, 2025. Eighty-five of those probationary employees chose to return. On March 31, 2025, DOE opened a second DRP and voluntary early retirement enrollment period which closed April 11, 2025. The Secretary of Energy has yet to make final decisions on which Bonneville employees will be allowed to accept the second DRP or early retirement offers. Bonneville continues to assess how the staffing reductions will impact its operations but is confident essential functions to maintain the reliability and resilience of the Federal System will not be materially affected.

Among those departing from Bonneville are two senior executives who are retiring from federal service: Chief Operating Officer Joel Cook and Senior Vice President of Transmission Services Richard Shaheen.

Chief Operating Officer Joel Cook, who joined Bonneville in 2017 after a lengthy career in the utility industry, retired from federal service effective March 1, 2025. Mr. Cook has served as Bonneville's Chief Operating Officer since April 25, 2021, Previously, he served as Senior Vice President for Power Services. Due to the federal hiring freeze currently in effect, Bonneville is unable to fill this role. Suzanne Cooper, Senior Vice President of Power Services, will be delegated the authorities of the Chief Operating Officer until the position can be permanently filled.

Also retired as of March 1, 2025, is Senior Vice President of Transmission Services Richard Shaheen. Mr. Shaheen joined Bonneville in 2013 as Vice President of Bonneville's Engineering and Technical Services organization after a 25-plus year career at a large electric utility. Mr. Shaheen was named Senior Vice President of Transmission Services in 2014. Due to the federal hiring freeze currently in effect, Bonneville is unable to fill this role. Mike Miller, Vice President of Transmission Engineering, will be delegated the authorities of the Senior Vice President of Transmission Services until the position can be permanently filled.

In addition to the retirements of Bonneville's Chief Operating Officer and its Senior Vice President of Transmission Services, Bonneville's Chief Financial Officer, Marcus Harris, separated from Bonneville in January 2025, to join Energy Northwest as their Chief of Executive Projects. Deputy Chief Financial Officer Veronica Wittig will act as the Chief Financial Officer until the position can be permanently filled.

Additionally, Bonneville's partners at the Corps and Reclamation also experienced unexpected retirements and layoffs. Both agencies are working to mitigate the impacts.

On February 1, 2025, the President, using the International Emergency Economic Powers Act, instituted a 10 percent tariff on energy imports from Canada. Bonneville expects the tariff to have a slight upward pressure on power prices in the Region. Other potential tariffs on construction related materials sourced internationally could create upward pressure on Bonneville's construction costs but Bonneville is unable to predict the extent of the impact at this time.

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 $3.4 billion (excluding "bookouts" from settlements other than by the physical delivery of power) in revenues, or 73 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 2024.

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 Federal Transmission System and certain other features, constitute the Federal System. The Federal System includes those portions of the federal investment in the Federal System Hydroelectric Projects that have been allocated by federal law or policy to power generation for repayment. 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 the tenth percentile of the Federal System output result for the Columbia River basin referred to herein as "Low Water Flows" (and is frequently referred to by Bonneville as "Firm 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 2026 (August 1, 2025 through July 31, 2026), the total Federal System would be capable of producing approximately 7,912 annual average megawatts of firm energy under Firm Water conditions and not accounting for transmission line losses. This generation includes approximately 6,536 annual average megawatts from Reclamation and Corps hydro projects, approximately 1,116 annual average megawatts from Columbia Generating Station and other non-federally-owned resources (including hydropower and renewable generation projects), and approximately 227 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 2026."

Analyses as of April 27, 2025, prepared by an entity apart from Bonneville but relied on by Bonneville for planning purposes, indicate that the Fiscal Year 2025 water supply for the Columbia River basin will be approximately 87 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. Runoff amounts are determined to a great degree by late fall, winter, and early spring precipitation.

Federal Hydro-Generation

The share of hydropower from the Federal System Hydroelectric Projects and a small amount of power Bonneville has acquired from non-federally-owned hydroelectric projects for Operating Year 2026 is estimated to be approximately 85 percent of Bonneville's total firm power supply under Firm Water. See the table entitled "Operating Federal System Projects for Operating Year 2026." 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.

The Federal System as primarily a hydropower system, with access to substantial reservoir storage, has peaking capacity that exceeds the 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 the Federal System with energy purchases (or similar actions) in order to balance annual and seasonal firm energy needs, these additions contribute more peaking capacity.

At this time, Bonneville's resource planning focuses primarily on the need to acquire sufficient firm energy resources to meet firm energy loads. In contrast, most utilities with coal, gas, oil, and nuclear based generating systems must also focus their resource planning and acquisition on having enough peaking capacity to meet peak loads. As additional non-power requirements are placed on the Federal System hydroelectric operations and as Bonneville's peak load obligations grow, it may become necessary for Bonneville to plan for additional peaking capacity from resources or purchases to meet peak load obligations. See "—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Bonneville's Obligation to Meet Certain Firm Power Requirements in the Region—Bonneville's Resource Program and Bonneville's Resource Strategies."

In general, for long-term planning purposes Bonneville estimates the amount of electric power it will need in order to meet loads above the expected Federal System firm power generated under Low Water Flows/Firm Water. Firm energy from hydro reflects generation under assumptions of low streamflow derived from Regional streamflow records Thus, the fuel supply (streamflow) and generating capability for firm energy from hydro have a high probability of occurring from year to year.

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 amount of seasonal surplus energy generated by the Federal System that is above the amount needed to meet Bonneville's Regional loads depends primarily on precipitation and reservoir storage levels, thermal plant performance (the Columbia Generating Station), and other factors. For Operating Year 2026, the Federal System is forecast to generate seasonal surplus energy of 1,248 annual average megawatts, assuming median water conditions (50th percentile). In years with high water conditions (90th percentile) the amount of seasonal surplus energy could be as much as 3,268 annual average megawatts. In years with Low Water Flows/Firm Water, the amount of seasonal surplus energy generated by the Federal System could be quite small or not available at all.

Notwithstanding that the amount and timing of seasonal surplus energy is subject to variability, Bonneville markets almost all seasonal surplus energy on a contractual basis under which the commitment to provide energy is firm.

The Corps and Reclamation operate the Federal System Hydroelectric Projects to serve multiple statutory purposes. These purposes include flood control, irrigation, navigation, recreation, municipal and industrial water supply, fish and wildlife protection, as well as 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 "Operating Federal System Projects for Operating Year 2026" 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 those: (i) in furtherance of the ESA as set forth by the NOAA Fisheries in biological opinions relating to the operation of the Federal System dams on the Columbia River and Snake River and tributaries and under related court-ordered operations, (ii) in furtherance of the ESA as set forth by the Fish and Wildlife Service in biological opinions relating to operation of certain Federal System dams on the Snake River, Columbia River, and tributaries, 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 electric power resources, apart from the hydropower generating resources, includes power from the Columbia Generating Station, which has the largest capacity for energy production of the non-federal resources included in the Federal System. See Footnote 10 in the "Operating Federal System Projects for Operating Year 2026" table. In addition, Bonneville has a number of power purchase and related contracts under which Bonneville receives electric power and which are not tied to specific generating resources ("Other Federal Contracts"). Bonneville projects that it will continue to have long-term contracts for power purchases, power or energy exchanges, power purchased or assigned under the Columbia River Treaty, transmission loss returns under the "Slice" contracts (as described below, under Slice service, Bonneville commits to provide a Slice product under which the purchaser receives a proportionate share of the actual output of the Federal System as generated) and similar non-federal transactions. In aggregate these arrangements will provide approximately 227 annual average megawatts of firm energy in Operating Year 2026. See Footnote 12 in the following table "Operating Federal System Projects for Operating Year 2026."

Operating Federal System Projects for Operating Year 2026

In all years, the energy generating capability of the Federal System Hydroelectric Projects depends upon the amount of water flowing through such facilities, the physical capacity of the facilities, streamflow requirements pursuant to biological opinions, and other operating limitations. Bonneville utilizes the last 30-years of the 90–year historical streamflow record (the 2020 Modified Streamflows) since it provides the most accurate reflection of expected future streamflows. During this period, Bonneville estimates the energy generating capability of Federal System Hydroelectric Projects in any given operating year by assuming that these historical water conditions reflect what will occur in that specific operating year and making adjustments in the expected generating capability to reflect the current physical capacity operating limitations and current streamflow 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 2026, the Federal System Maximum Capacity and energy capability using (i) Low Water Flows at the 10th percentile (referred to as "Firm Energy"), (ii) median water conditions at the 50th percentile (referred to as "Median Energy"), and (iii) high water conditions at the 90th percentile (referred to as "High 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. See "POWER SERVICES—Certain Statutes and other Matters Affecting Bonneville's Power Services—Fish and Wildlife—The Endangered Species Act" and "BONNEVILLE LITIGATION—Columbia River ESA Litigation."

Operating Federal System Projects for Operating Year 2026[1]

Project	Initial Service Year	Number of Units	Maximum Capacity (MW)[2]	High Energy (aMW)[3]	Median Energy (aMW)[4]	Firm Energy (aMW)[5]
United States Bureau of Reclamation (Reclamation) Hydro Projects						
Grand Coulee including Pump Turbine	1941	33	6,998	3,000	2,292	1,886
Hungry Horse	1952	4	310	127	96	81
Other Reclamation Projects[6]		19	300	170	145	116
1. Total Reclamation Projects		56	7,608	3,297	2,533	2,083
United States Army Corps of Engineers (Corps) Hydro Projects						
Chief Joseph	1955	27	2,614	1,732	1,387	1,111
John Day	1968	16	2,480	1,334	996	777
The Dalles w/o Fishway[7]	1957	22	2,080	1,064	819	634
Bonneville	1938	18	1,221	709	532	381
McNary	1953	14	1,120	642	545	447
Lower Granite	1975	6	930	320	192	128
Lower Monumental	1969	6	930	317	198	136
Little Goose	1970	6	930	335	219	147
Ice Harbor	1961	6	693	275	187	135
Libby	1975	5	605	289	224	189
Dworshak	1974	3	465	283	201	181
Other Corps Projects[8]		20	574	193	171	158
2. Total Corps Projects		149	14,642	7,493	5,671	4,424
3. Total Reclamation and Corps Projects (line 1 + line 2)		**205**	**22,250**	**10,790**	**8,204**	**6,507**
Non-Federally-Owned Projects						
Other Non-Federal Hydro Projects[9]		4	72	33	30	27
Columbia Generating Station[10]	1984	1	1,178	1,116	1,116	1,116
Other Non-Federal Projects[11]		7	-	33	33	33
4. Total Non-Federally-Owned Projects		**12**	**1,250**	**1,182**	**1,179**	**1,176**
Federal Contract Purchases						
5. Total Bonneville Contract Purchases[12]		**n/a**	**454**	**244**	**234**	**227**
Total Federal System Resources						
6. Total Federal System Resources (line 3 + line 4 + line 5)		**217**	**23,954**	**12,216**	**9,617**	**7,910**

Source: 2024 Pacific Northwest Loads and Resources Study, Bonneville, August 2024.

(1) Operating Year 2026 is August 1, 2025 through July 31, 2026. Any discrepancies in totals for figures portrayed in this table and the 2024 Pacific Northwest Loads and Resources Study are due to rounding.

(2) Maximum Capacity represents full capacity of resources including overload.

(3) High Energy capability is the estimated amount of hydroelectric energy to be produced using high water conditions at the 90th percentile for energy in annual average megawatts ("aMW"). Bonneville's hydro-regulation study incorporates spill assumptions similar to the Selected Alternative published in the 2020 Columbia River System Biological Opinion for the Snake River and Columbia River dams. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Developments Relating to the Endangered Species Act" and "—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 conditions at the 50th percentile for energy, in aMW.

(5) Firm Energy capability is the estimated amount of hydro energy to be produced using Low water Flows at the tenth percentile for energy, in aMW.

(6) Other Reclamation Projects include: Anderson Ranch (1950), Black Canyon (1925), Boise Diversion (1908), Chandler (1956), Green Springs (1960), Minidoka (1909), Palisades (1957), 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) Other Non-Federal Hydro Projects include project capability from the following hydroelectric projects estimated by water conditions: Lewis County PUD's Cowlitz Falls Project (1994), the State of Idaho Department of Water Resources' Clearwater Hydro (1998), Dworshak Small Hydro (2000), and Rocky Brook Hydro (1999). Bonneville has acquired the output from the Cowlitz Falls Project through June 30, 2032. If Bonneville's contracts to purchase power from any of these projects change or are renewed, those changes will be reflected in future studies.

(10) Columbia Generating Station operates under a biennial maintenance and refueling schedule. Bonneville assumes that the Columbia Generating Station is expected to provide approximately 994 aMW in most refueling years and 1,116 aMW in non-refueling years. Columbia Generating Station is scheduled for refueling in Operating Year 2025 and, therefore, is expected to provide approximately 994 aMW in such operating year. 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—Renewable Generation Development and Integration into the Federal Transmission System."

(11) Other Non-Federal Projects include project output from the following projects: a share of PacifiCorp Power Marketing/Florida Light and Power's Stateline wind project and a share from NWW Wind Power's Klondike Phase III (2007).

(12) Federal Contract Purchases include contracts for power purchases, exchanges, and other non-federal transactions with entities (including from non-federal hydro projects) from both inside and outside the Region and from Canada. This also includes amounts of power returned from Slice customers for transmission line losses.

Bonneville's Power Trading Floor Activities

Much of Bonneville's generation resource base is provided by hydroelectric facilities, the output of which is affected by weather conditions, streamflow, operating constraints, and other factors. In most years, Bonneville sells substantial amounts of seasonal surplus energy in market-based transactions. In addition, other generation conditions and operational requirements may affect generation output. Thus, actual surplus generation will vary hourly, daily, monthly, or seasonally. In addition, power loads fluctuate based on consumer usage, demands to maintain transmission system stability, and other factors. Loads and the availability of generation from Bonneville's own resources can vary substantially and actual power from Bonneville's own generating resources may not match its loads. When Bonneville's loads exceed its generation capabilities, Bonneville buys energy in market-based transactions. In the near-term (prior to and during a fiscal year), Bonneville routinely produces probabilistic and discrete energy inventory 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 hourly, within-month, and forward transactions of physical power, futures, and power put and call 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), (ii) the level and volatility of market prices for electric power in western North America, which affect the revenues Bonneville receives from sales of surplus energy and capacity and the cost of necessary power purchases Bonneville may have to make to meet contracted loads and hydraulic objectives, (iii) the level of Bonneville's load serving obligation, (iv) 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, (v) 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, (vi) continued availability of existing Federal System generating resources, (vii) transmission availability influenced by planned maintenance and unplanned outages or de-rates associated with extreme weather events, and (viii) operating costs, generally.

Bonneville has put in place risk management procedures, standards, and policies that it believes adequately mitigate risk from these activities. Nonetheless, Bonneville's exposure to operational variability means that Bonneville may in certain conditions have to incur substantial purchased power expense. See "BONNEVILLE FINANCIAL OPERATIONS—Position Management and Derivative Instrument Activities and Policies."

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

Bonneville's primary firm power customers are composed of several principal groups: Preference Customers, DSIs, Federal Agencies and Regional IOUs. Bonneville enters into contracts to sell surplus power with parties ("Market Counterparties"), which are commercial power-related arrangements that are not derived or originally derived from Bonneville's statutory firm power obligations. See "—Market Counterparties and Exports of Surplus Power to the Pacific Southwest." Under the Northwest Power Act, Bonneville has a statutory obligation to meet electric power loads in the Region that are placed on Bonneville by electric power utilities. See "—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Bonneville's Obligation to Meet Certain Firm Power Requirements in the Region."

Credit Risk

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

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, consumer-owned electric cooperatives, and tribal utilities 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 firm power at Bonneville's lowest cost rate, the PF Preference Rate, for most of their loads. Under Public Preference, Bonneville must first meet a Preference Customer's request for available Federal System power over 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 surplus power to Preference Customers before meeting a competing request at a higher price for such 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.

For Operating Year 2026, Bonneville forecasts that it will meet approximately 6,800 annual average megawatts of Preference Customer loads.

Direct Service Industrial Customers

Bonneville may sell, but is not required by federal law to sell, power to a limited number of DSIs within the Region for their direct consumption. Historically, Bonneville's service to DSIs was to supply power to serve aluminum smelting or processing facilities. Such entities and load are no longer supplied by Bonneville under any power sales contracts since they have ceased to operate. Currently, Bonneville has one long-term contract to sell power at the IP Rate directly to one DSI—Port Townsend Paper Company—in an aggregate amount of up to 11 annual average megawatts.

Reclamation and Other Federal Agency Customers

Bonneville is required by federal law to provide firm power to Reclamation for certain irrigation pumping stations. For Operating Year 2026, Bonneville forecasts that it will meet approximately 186 annual average megawatts of Reclamation loads. Bonneville is not required by federal law to meet the loads of other federal agencies but has long-term contracts to do so. For Operating Year 2026, Bonneville forecasts that it will meet approximately 156 annual average megawatts of the loads of federal agencies other than Reclamation. While Reclamation and the other federal agency customers do not qualify as Preference Customers, they are entitled to buy power from Bonneville at PF Preference Rates.

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 load in the Region that is not met by the Regional IOU with its own designated power supplies) beginning in Fiscal Year 2020 if such service was requested not later than the end of Fiscal Year 2016. Although none of the Regional IOUs made an election to purchase requirements power for Fiscal Years 2020 through 2028, thereby providing Bonneville with advance notice that there is no need to add resources or take other steps to meet these loads, Bonneville could still be required to serve any Regional IOU with electric power for their net requirements for Fiscal Years 2020 through 2028 if a Regional IOU were to request that Bonneville waive its contractual notice requirement. Any requirements power provided by Bonneville under these contracts would be priced at the New Resources Rate ("NR Rate"). This rate would in effect reflect Bonneville's marginal cost of resources used to supply such IOU load amount.

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 NR 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, and (iv) the NR Rate bears additional costs of statutory rate protection afforded to Preference Customers, thereby likely making the rate less economic compared to market alternatives.

Bonneville provides power to the Regional IOUs under contracts other than long-term firm requirements contracts. Bonneville also sells substantial amounts of peaking capacity to Regional IOUs. Power sales to Regional IOUs are distinct from Bonneville's contracts implementing the Residential Exchange Program, as provided by statute. The

Residential Exchange Program obligations, described herein, result in payments by Bonneville to participating utilities. See "—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Residential Exchange Program."

Market Counterparties and Exports of Surplus Power to the Pacific Southwest

Bonneville has a large number of parties with which it has commercial power-related arrangements that are not based on Bonneville's statutory obligations (as in the case of statutory load-meeting obligations to Preference Customers and Regional IOUs, and payment obligations under the Residential Exchange Program) or on long-term relationships that are based on prior statutory obligations (as in the case of DSIs). These counterparties include utilities located outside the Region, power marketers, and independent power producers. Transactions with these counterparties include, but are not limited to, arrangements for purchases of power, surplus power sales and/or exchanges of transmission, and related services. Of the foregoing contracts, those that involve long-term commitments are referred to by Bonneville in its loads and resources forecasts as "Other Contract Deliveries." The commitments include power deliveries to entities outside the Region ("Exports") and to entities within the Region ("Intra-Regional Transfers (Out)"). The terms of these deliveries are specified by individual provisions and have various delivery arrangements and rate structures and Bonneville assumes in its load forecasts that such loads will be served by Federal System firm resources regardless of weather, water, or economic conditions. For Operating Year 2026, Bonneville forecasts that Other Contract Deliveries will be approximately 591 annual average megawatts.

Bonneville sells surplus power via the Pacific Northwest-Pacific Southwest Intertie (the "Southern Intertie") transmission lines to Pacific Southwest utilities, power marketers, the California Independent System Operator ("Cal-ISO"), and other entities, which use most of such power to serve California loads. These sales are composed of surplus firm power and seasonal surplus energy that is not needed to meet Bonneville's Regional energy requirements. Sales 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 before offering such power to a customer outside the Region. Any Regional customer that elects to step in front of a proposed extra-regional sale must accept the same terms, conditions, and price offered.

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 withhold delivery of such power, upon advance notice, if needed to meet the energy requirements of Bonneville's Regional customers. 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 a large share of Bonneville's sales of seasonal surplus energy. These transactions account for a large share of revenues from Bonneville's Regional exports. The amount of seasonal surplus energy that Bonneville has available to sell depends on precipitation and other power supply factors in the Northwest, the available transmission capacity of the Southern Intertie, the attributes of power markets across the Western Electricity Coordination Council ("WECC"), and other factors that may constrain exports notwithstanding the availability of power.

While Bonneville designs its power rates to recover its costs, it does so with an expectation that some revenue will be the result of surplus power sales at competitive pricing terms in the wholesale electricity marketplace. Revenues that Bonneville obtains from these surplus sales depend on market conditions and the resulting prices. These revenues are affected by the weather and other factors that affect demand in the Pacific Northwest and Southwest, and the cost and availability of alternatives to Bonneville's power. The value of such surplus power sales is frequently dependent on other electric energy suppliers' resource costs such as the cost of hydropower or 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 exported outside the Pacific Northwest. Such sales may be limited, however, by transmission capacity and other factors.

Power Services' Largest Customers

The following table lists Power Services' top ten largest customers in terms of their percentage contribution to Power Services' overall sales revenue in Fiscal Year 2024.

Bonneville Power Services' Ten Largest Customers By Sales[(1)]
(Percentage of Aggregate Power Services' Sales Revenue in Fiscal Year 2024)

Customer Name	Approximate % of Sales
Snohomish County PUD No 1 (Preference Customer)	8%
Pacific Northwest Generating Cooperative (Preference Customer)[(2)]	7%
City of Seattle, City Light Dept (Preference Customer)	5%
Cowlitz County PUD No 1 (Preference Customer)	5%
Amazon Energy LLC (Power Marketer)	4%
Tacoma Power (Preference Customer)	3%
Portland General Electric Company (Regional IOU)	3%
Clark Public Utilities (Preference Customer)	3%
Transalta Energy Marketing (US) Inc (Power Marketer)	3%
Eugene Water & Electric Board (Preference Customer)	2%

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

(2) The Pacific Northwest Generating Cooperative is a joint operating agency that buys federal power from Bonneville on behalf of 16 electric cooperatives—each a Preference Customer—to supply their aggregated load demand.

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.

Under the Northwest Power Act, when requested, Bonneville must offer a contract for the sale of firm power to each eligible utility, which includes Preference Customers and Regional IOUs, to meet that portion of the utility's Regional firm power loads net of the non-federal resources used by the customer to supply its load. 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. Bonneville refers to this as its "net requirements" obligation. If Bonneville has or expects to have inadequate power and reasonably determines it cannot acquire resources 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 have generating resources, which they may use to meet their firm loads in the Region. Each of such customers has to identify the amount of its loads it would meet with its own resources, thereby providing Bonneville with advance notice of the need to add resources or take other steps to meet these loads. These provisions are included in Bonneville's currently effective Long-Term Preference Contracts. The Long-Term Preference Contracts include provisions that enable Preference Customers to put additional net requirements load ("Tier 2 Loads") on Bonneville above a baseline level of loads ("Tier 1 Loads") reflective of loads placed on Bonneville prior to the commencement of power sales under Long-Term Preference Contracts.

Bonneville is also directed by federal law to provide electric power from the Federal System to Reclamation to operate 13 separate water pumping projects. See "—Regional Customers and Other Power Contract Parties of Bonneville's Power Services—Reclamation and Other Federal Agency Customers."

Long-Term Preference Contracts, Federal Agency Sales, and Related Power Products. Bonneville currently provides three primary types of power service under the Long-Term Preference Contracts and its sales agreements with federal agencies: (i) Load Following service, (ii) Block service, and (iii) Slice/Block service, which is an integrated power product combining Slice of the System (or "Slice") and Block power. Under Load Following service, Bonneville provides the actual power requirements of the related customer (this is also known as "Full Requirements" product). Under Block service, the customer receives planned or fixed amounts of power at designated times. Under Slice/Block service, Bonneville commits to provide a Slice product under which the purchaser receives a proportionate share of the actual output of the Federal System as generated, and a "Block" product under which the customer receives fixed amounts of power at designated times.

Approximately 122 Preference Customers and all of Bonneville's seven federal agency customers purchase Load Following service and for Operating Year 2026 Bonneville forecasts that these loads will be approximately 3,981 annual average megawatts. By contrast, 10 separate Preference Customers purchase on a Slice/Block basis. For Operating Year 2026, Bonneville forecasts that its Slice/Block loads will be approximately 2,591 annual average megawatts in total, approximately half of which is expected to be for the Block portion and approximately half of which is expected to be for the Slice portion.

For reference, the Slice portion of Slice/Block service currently represents approximately 20 percent of a contractually-established measure of the output of the Federal System Hydroelectric Projects, the Columbia Generating Station, certain other non-federally-owned generation projects, and the electric power available to Bonneville after netting receipts and deliveries of power under certain long-term power transactions. The foregoing load forecasts reflect an attempt to predict actual loads that will be met under the specified type of service, which loads vary with weather, economic and other conditions.

Bonneville provides all of the foregoing power products at PF Preference Rates, although the particular rate features, levels and determinants vary depending on the power product. All of the Long-Term Preference Contracts and the federal agency power sales subject the customers to a payment commitment under which they are required to pay for power that is tendered by Bonneville in conformity with the applicable power sales contract. For Slice, the customers pay a fixed percentage of the costs of the Federal System generation without regard to the amount of power actually generated. In either case, if a customer's net requirements decline, the customer's purchase obligation from Bonneville is reduced commensurately. For Slice/Block, the customers' obligations and rights to purchase power are similarly capped by their net requirements. If their net requirements decline, the Block portion is reduced first.

Tiered Rates for Long-Term Preference Contracts. Prior to Fiscal Year 2012, when Bonneville augmented Federal System resources with long-term power purchases or other generating resources, the costs of these typically more expensive purchases were, in general, melded with the Federal System's low, embedded-cost power, creating integrated power rates that masked both the real value of then-existing Federal System power and the incremental costs of meeting load growth. This cost-melding effect created incentives for Preference Customers to place incremental load growth on Bonneville and exposed Bonneville to certain associated risks relating to obtaining electric power to meet the incremental loads. Under the Long-Term Preference Contracts, Bonneville sells at PF Preference Rates that are "tiered" so that power that Bonneville sells to meet the incremental Preference Customer loads above a baseline level of loads is provided at rates that directly and exclusively recover the associated costs that Bonneville incurs in meeting such incremental loads. The Long-Term Preference Contracts involve two tiers of power rates, which Bonneville expects to establish biennially in all but the final three years of Long-Term Preference Contracts: "Tier 1 PF Rates" and "Tier 2 PF Rates."

Tier 1 PF Loads and Tier 1 PF Rates. Preference Customers (and federal agencies) purchase a limited amount of power at Tier 1 PF Rates, which rates in general reflect the historically embedded costs of power from the Federal System. A customer's right to purchase power at Tier 1 PF Rates is capped in general at an amount equal to the net requirement loads it placed on Bonneville in Operating Year 2010 (with certain possible adjustments) ("Tier 1 Loads"), thus, the aggregate amount of power that can be purchased at Tier 1 PF Rates in general reflects the generating output of the Federal System in Fiscal Year 2010 (updated with each rate period to reflect changed Federal System generation expectations). The aggregate amount of power loads served at Tier 1 PF Rates in Fiscal Year 2024 was 6,972 annual average megawatts. The aggregate amount of power loads to be served at Tier 1 PF Rates has been estimated at 7,002 annual average megawatts in Fiscal Year 2025, 6,973 annual average megawatts in Fiscal Year 2026, 7,003 annual average megawatts in Fiscal Year 2027, and 7,027 annual average megawatts in Fiscal Year 2028.

If and to the extent that the existing Federal System resources (including the Columbia Generating Station) whose costs are allocated for recovery in Tier 1 PF Rates were to decline in capability, Tier 1 PF Rates would nonetheless continue to recover the costs of the related resources. The amount of power that Bonneville would be obligated to sell at Tier 1 PF Rates would also decline commensurate with the reduction in resource capability, although the reduction in obligation to sell at Tier 1 PF Rates would not occur until the rate period following the rate period in which the resource capability reduction occurred.

The aggregate amount of power available to be purchased at Tier 1 PF Rates may also be expanded in certain limited circumstances: (i) up to 70 annual average megawatts to serve an increase in DOE load, and (ii) up to 250 annual average megawatts in aggregate, if necessary, for new Preference Customers and load growth of certain tribal utility customers. From time to time, Bonneville receives inquiries from interested parties about becoming new Preference Customers. Bonneville is unable to predict whether additional new Preference Customers will form or the amount of power, if any, they will purchase from Bonneville at Tier 1 PF Rates.

Bonneville follows a "Tiered Rates Methodology" in each rate proceeding to allocate costs and set the respective Tier 1 PF Rates and Tier 2 PF Rates. Costs that are and will be allocated to Tier 1 PF Rates include but are not limited to: the costs assigned to power rates for the Net Billed Projects (some Net Billed Project debt service costs are assigned to be recovered in Transmission Services rates), Federal System fish and wildlife costs, electric power conservation programs, power benefits (if any) to be provided to DSIs, and Residential Exchange Program benefits. Under the Tiered Rates Methodology, most of the benefits of seasonal surplus energy from the Federal System are provided to Preference Customers in Tier 1 PF Rates. In the case of Slice, those customers receive a proportionate share of Federal System seasonal surplus energy to use for native loads (or to market in the case of a small portion of Slice which is a non-requirements product). The revenue benefits that Bonneville receives from its own marketing of seasonal surplus energy are allocated to non-Slice Tier 1 PF Rates (primarily, to rates for Block and Load Following power products).

Tier 2 PF Rates and Tier 2 Loads. In contrast to Tier 1 Loads, "Tier 2 Loads" are loads that a customer places on Bonneville that are incremental to the customer's right to purchase at Tier 1 PF Rates. Under the Tiered Rates Methodology, Tier 2 PF Rates recover only the cost to Bonneville of meeting Tier 2 Loads for Preference Customers that elect to purchase power from Bonneville to meet Tier 2 Loads. Such purchases are integrated with purchases of power for Tier 1 Loads into a single power purchase, although the purchase of power from Bonneville for Tier 2 Loads is made on a take-or-pay basis for the specified amount of power.

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

Bonneville is obligated to meet approximately 402 annual average megawatts of Tier 2 Loads in Fiscal Year 2025, approximately 548 annual average megawatts in Fiscal Year 2026, approximately 595 annual average megawatts in Fiscal Year 2027, and approximately 635 annual average megawatts in Fiscal Year 2028. Tier 2 Loads were 157 annual average megawatts in Fiscal Year 2022, 173 annual average megawatts in Fiscal Year 2023, and 211 annual average megawatts in Fiscal Year 2024.

Comparison of Tier 1 PF Rates and Tier 2 PF Rates. When developing the Tiered Rate Methodology, Bonneville expected that Tier 1 PF Rates would typically be lower than Tier 2 PF Rates because the embedded cost structure for power from the existing Federal System (in general, as of the time of the commencement of power sales under the Long-Term Preference Contracts, which costs are and will be allocated for recovery in Tier 1 PF Rates) would likely be lower than the cost of new resources obtained to meet Tier 2 Loads and allocated for recovery in Tier 2 PF Rates. However, given low market prices for electric power in Fiscal Year 2020 through Fiscal Year 2023, Tier 2 PF Rates were lower than Tier 1 PF Rates during that period. Under the Final 2022-2023 Rates, average Tier 2 PF Rates were approximately $33.65 per megawatt hour and average Tier 1 PF Rates were approximately $34.93 per megawatt hour (exclusive of any rate adjustment mechanisms). Under the Final 2024-2025 Rates, average Tier 2 PF Rates are approximately $61.50 per megawatt hour and average Tier 1 PF Rates are approximately $34.69 per megawatt hour. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Power Rates for Fiscal Years 2024-2025." The Tier 2 PF Rate does not reflect a long-term commitment, but an election by customers to request that Bonneville serve its Tier 2 Load on a rate period by rate period basis. Prior to Fiscal Year 2020, Bonneville made longer advance purchases to serve its anticipated Tier 2 Loads, but since then Bonneville began and continues to make purchases to serve its Tier 2 Loads closer in time to when Tier 2 elections are made and Tier 2 Load commitments are known (just before the start of each rate period) or, if available, uses its surplus power valued at forward market prices to meet Tier 2 Loads. The Tier 2 Rate increase for the Final 2024-2025 Rates is due to higher forecast market prices for electricity (which is the basis for forecast power purchase costs or the average sales price for surplus sales in each year of the rate period).

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 and compares that to expected generating resources and other supply arrangements.

With the adoption of Bonneville's 2024 Pacific Northwest Loads and Resources Study, Bonneville projected that it would have an energy deficit of approximately 79 annual average megawatts in Operating Year 2026, and an energy deficit of approximately 139 annual average megawatts in Operating Year 2027, assuming Firm Water and transmission line losses. Between Operating Years 2025 and 2034, Bonneville forecasts annual planning deficits that vary between 79 annual average megawatts (in Operating Year 2026) and 303 annual average megawatts (in Operating Year 2033). In Bonneville's opinion, the foregoing deficits do not present significant planning deficits given the size of the Federal System and the availability of various measures to meet such a planning deficit. Bonneville expects that it would be able to meet such a planning deficit with seasonal surplus energy from the Federal System, market purchases, and/or other actions. The foregoing load/resource balance forecast takes into account, among other items (i) forecasts of Federal System generation together with power from purchases, exchanges and other agreements, (ii) forecasts of savings from electric power conservation measures, and (iii) forecasts of the loads of Preference Customers, DSIs, Reclamation, federal agencies other than Reclamation, and contract commitments arising under Other Contract Deliveries.

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 supply obligations, (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 load obligations, (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 Acquire Resources. In order to assure it has adequate power supplies to meet its load obligations, Bonneville has authority to acquire resources 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 enter into contracts for the acquisition of "resources" to serve firm loads pursuant to certain procedures and standards set forth in the Northwest Power Act. "Resources" are defined in the Northwest Power Act to mean: (i) electric power, including the actual or planned electric power capability of generating facilities; or (ii) the actual or planned load reduction resulting from direct application of a renewable resource by a consumer, or from conservation measures. "Conservation" is defined in the Northwest Power Act to mean measures to reduce electric power consumption as a result of increased efficiency of energy use, production, or distribution.

Bonneville's statutory responsibility to meet its firm power contractual obligations has led and is expected to lead Bonneville to acquire conservation resources and has led and may in the future lead Bonneville to acquire the output of generation resources. The extent to which Bonneville does so will depend on available resources, the effects of electric power markets, power sales contract terms, forecasted load growth, and other factors.

The authority to acquire resources under the Northwest Power Act, however, is not the sole authority by which Bonneville may meet its power requirements. Other authorities and methods are available. These include, but are not limited to: (i) exchange of surplus Bonneville peaking capacity for firm energy under the Bonneville Project Act; (ii) receipt of additional power from improvements at federally- and non-federally-owned generating facilities; and (iii) short-term purchases of power under the Transmission System Act for periods of less than five years.

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

The Council released its Eighth Northwest Conservation and Electric Power Plan (the "Eighth Power Plan") in February 2022, which provides updated guidance for Bonneville's energy efficiency program in suggested scale of acquisitions and types of most cost-effective energy efficiency. The Power Plan looks forward over a 20-year horizon and includes a six-year action plan for utilities and other parties in the Region, including Bonneville. The Council, Bonneville and other parties around the Region continue to implement provisions of the action plan. The Eighth Power Plan continues to rely on energy efficiency to meet future energy needs and the Council's analysis shows that energy efficiency can meet the Region's expected load growth and calls for the installation of 1,400 average megawatts of energy efficiency by the end of calendar year 2027, including a specific target for Bonneville to acquire between 270 and 360 average megawatts of cost-effective energy efficiency during the six-year period. This is a reduction over the higher levels achieved under the previous plan. The Eighth Power Plan also recommends the development of demand response resources and use of increased market imports to meet future system capacity needs under critical water and weather conditions.

Based on the Eighth Power Plan and Bonneville's 2022 Resource Program (as defined below), Bonneville drafted an Energy Efficiency Action Plan for the five-year period ending on December 31, 2027. The Energy Efficiency Action Plan establishes a target of acquiring 300 average megawatts of energy efficiency by the end of calendar year 2027, and accounts for the priorities set by both the Eighth Power Plan and Bonneville's Resource Program.

Consistent with the Council's analysis, achieving the Council's energy efficiency goal helps Bonneville and other utilities in the Region manage future Regional load growth and address future Regional peaking capacity needs. See "—Bonneville's Resource Program and Bonneville's Resource Strategies."

Bonneville's Resource Program and Bonneville's Resource Strategies. Bonneville's long-range resource planning involves the evaluation of whether Bonneville may need to acquire resources to meet its power supply obligations and the best means by which to meet those needs. Bonneville periodically analyzes its needs for annual energy as well as monthly/seasonal heavy load hour energy and capacity in extreme weather events, which inform Bonneville's Resource Program.

Bonneville's most recent Resource Program, which was published in calendar year 2025 (the "2024 Resource Program"), studied Fiscal Years 2026-2044 and found that the Federal System is expected to experience energy deficits in heavy load hours at the average monthly level under low-water conditions, with deficits most pronounced in the winter and late summer. As in prior Resource Programs, the 2024 Resource Program concluded that Bonneville, in addition to existing resources, can satisfy much of its expected supply obligations with electric power conservation and short-term power purchases from wholesale power markets.

Short-Term Power Purchases. Under the Long-Term Preference Contracts, customers may meet their own incremental loads or turn to Bonneville to meet such loads. To meet potential new loads, and consistent with the Resource Program, Bonneville believes that, in general, new sources of power should have fixed costs that can be recovered over a shorter period, should provide power in the times of the year when power is required, should be capable of being displaced when hydroelectric power is available, and should have costs that can be offset when hydroelectric power is available. Short-term purchases are the one type of resource that meets incremental load obligations without incurring long-term fixed costs.

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

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

In contrast to a reliance on long-term generating resource acquisitions, a short-term purchase strategy should reduce the possibility that Bonneville would over-commit to long-term purchases and be forced to sell consequent surpluses at low prices in the market. Nonetheless, it is still possible, even with a short-term purchase strategy, that Bonneville could purchase more energy than needed and have to sell consequent surpluses at low prices. Dependence on short-term purchases also may make access to transmission a more important issue than reliability of generation. Bonneville uses a short-term energy purchase approach in meeting Tier 2 Loads.

Electric Power Conservation. Bonneville has electric power 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. In the 2024-2025 Rate Period, Bonneville forecasts that it will achieve up to 112 average megawatts of conservation.

Renewable Energy. Bonneville presently purchases a total of approximately 33 annual average megawatts from various wind energy projects in Oregon and Washington.

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 farm power users in the Region that are served by utilities that have high average system costs. 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 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, transmission, and general 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.

Bonneville, its Preference Customers, and all six Regional IOUs currently operate under the "2012 Residential Exchange Program Settlement." The settlement fixes the amount of aggregate program benefits and actual aggregate cash payments for the Regional IOUs from Fiscal Year 2012 through Fiscal Year 2028. Residential Exchange Program benefits are the nominal financial benefits to be received from Bonneville by an exchanging utility. Actual aggregate cash payments are the actual payments to be paid by Bonneville to an exchanging utility. For the remaining five years of the settlement agreement term, the schedule of aggregate program benefits for the Regional IOUs ranges from \$274 million to \$286 million per fiscal year. For more details related to Bonneville's Residential Exchange Program commitments, see Appendix B-1 to the Official Statement (Note 10 to the Fiscal Year 2024 Audited Financial Statements).

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 the Federal System Hydroelectric Projects, which are located 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 Fish and Wildlife Program. See "—Council's Fish and Wildlife 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 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 risk management).

Bonneville also funds and implements fish and wildlife mitigation measures that are consistent with the Council's Fish and Wildlife Program and the other purposes of the Northwest Power Act. The Council's Fish and Wildlife Program calls for a variety of mitigation measures from habitat protection to main-stem Columbia River and Snake River operations for fish. When such measures 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 a cost of the measures borne by Bonneville. While many of the measures in the Council's Fish and Wildlife Program are integrated with and form a substantial portion of the measures undertaken by Bonneville in connection with the ESA, the Council's Fish and Wildlife 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." Direct Costs include: (i) "Integrated Program Costs," which are the costs to Bonneville of implementing projects in support of the Council's Fish and Wildlife Program, and which include expenses for ESA-related and some non-ESA-related measures that are located at sites away from the Federal System Hydroelectric Projects, (ii) "Expenses for Recovery of Capital," which include depreciation, amortization and interest expenses for fish and wildlife capital investments by the Corps (Columbia River Fish Mitigation), Reclamation, and Bonneville, and (iii) Other Entities' Operations & Maintenance ("O&M")," which include fish and wildlife O&M costs of the Fish and Wildlife Service for certain fish hatcheries and of the Corps and Reclamation for Federal System projects. Columbia River Fish Mitigation is described in "—The Endangered Species Act."

Operational Impacts include "Replacement Power Purchase Costs" and "Foregone Power Revenues." Replacement Power Purchase Costs are the costs of certain power purchases made by Bonneville that are attributable to river operations in aid of fish and wildlife. To determine these costs in a given year, Bonneville compares the actual hydroelectric generation in such year against the hydroelectric generation that would have been produced had the Federal System Hydroelectric Projects been operated without any operating constraints due to fish and wildlife protection. To the extent that this comparison indicates that Bonneville made a power purchase to meet load, which purchase Bonneville would not have had to make had the river been operated without the constraints identified for fish, Bonneville accounts for such value as a fish and wildlife cost. Conversely, if the comparison indicates that Bonneville made fewer power purchases than would have been made had the river been operated without the constraints identified for fish, Bonneville accounts for such value as a negative fish and wildlife cost. "Foregone Power Revenues" are revenues that would have been earned absent changes in hydroelectric system operations attributable to fish and wildlife measures. The following table shows Bonneville's Fish and Wildlife costs by category for Fiscal Years 2022 through 2024.

Fish and Wildlife Financial Impacts by Type
(Unaudited)[2]
(Fiscal Years 2022-2024, dollars in millions)

	2024	2023	2022
Direct Costs	$ 477	$ 463	$ 451
Estimated Operational Impacts[1]:			
Replacement Power Purchase Costs	856	879	238
Foregone Power Revenues	37	89	252
Total	**$ 1,370**	**$ 1,431**	**$ 941**

(1) Unaudited metric that is not in accordance with GAAP.
(2) PricewaterhouseCoopers LLP, Bonneville's independent auditor, has not audited, reviewed, compiled, or applied agreed-upon procedures with respect to the financial data in this table. Accordingly, PricewaterhouseCoopers LLP does not express an opinion or any other form of assurance with respect to the financial data.

The variations in Direct Costs from year to year are the result of changes in reimbursable/direct-funded projects and fixed expenses. The variations in Replacement Power Purchase Costs and Foregone Power Revenues are the result of changes in prices due to energy market conditions, differences in monthly hydro generation shape, and changes in hydroelectric system operations resulting from biological opinions and related actions under the ESA (as described immediately below).

The Endangered Species Act. Operation of the Federal System Hydroelectric Projects by the Action Agencies is subject to the ESA. To a great extent, compliance with the ESA determines how the Federal System Hydroelectric Projects are operated to benefit fish and drives much of the fish planning and activities. The ESA listings and biological opinions have resulted in major changes in the operation of the Federal System Hydroelectric Projects, including a substantial loss of flexibility to operate the Federal System for power generation. Apart from changes in Federal System Hydroelectric Project operations that affect power generation, compliance with the ESA has also resulted in additional costs borne by Bonneville in the form of non-operational measures for the conservation of fish species funded from Bonneville revenues. Among other things, the ESA requires that federal agencies such as the Action Agencies ensure their actions are not likely to jeopardize the continued existence of listed species or result in the destruction or adverse modification of designated critical habitat. Since 1991, over a dozen anadromous and other marine species (including multiple stocks of salmon and steelhead, Southern Resident killer whales, North American green sturgeon, and eulachon) and two species of resident fish (bull trout and Kootenai River white sturgeon) that are affected by operation of the Federal System Hydroelectric Projects have been listed as threatened or endangered under the ESA. 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 Hydroelectric Projects on the Columbia and Snake Rivers are now operated for power production only after meeting needs for flood risk management 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 Project operations with respect to the listed anadromous salmonid species, and the Fish and Wildlife Service has developed biological opinions with respect to the listed resident fish species. These biological opinions provide information that the Action Agencies use to ensure that their actions with respect to the operation of the Federal System Hydroelectric Projects comply with the ESA. By operating the Federal System Hydroelectric Projects consistently with the biological opinions, the Action Agencies demonstrate that operation of the Federal System Hydroelectric Projects is not likely to jeopardize listed species or destroy or adversely modify designated critical habitat.

As described herein, the Action Agencies' compliance with the ESA in operating the Federal System Hydroelectric Projects has been the subject of litigation and judicial review and has resulted in court orders remanding biological opinions, including the 2014 Columbia River System Supplemental Biological Opinion for the Columbia and Snake Rivers. Operation of the Federal System Hydroelectric Projects consistent with the ESA has resulted in two principal changes in power generation. First, depending on water conditions, water that would otherwise run through dam turbines to generate electricity may be spilled to aid in downstream fish migration. Second, less water may be stored in the upstream reservoirs for fall and winter electric generation because more water is committed to use in the spring and summer to increase flows to aid downstream fish migration. Consequently, there is relatively less water available for hydroelectric generation in the fall and winter and more water available in the spring and summer. Because of these limitations, under certain water conditions, Bonneville has purchased and will purchase additional energy for the fall and winter to meet load commitments that would otherwise have been met with electric power from the Federal System Hydroelectric Projects. In addition, the flow changes have reduced the surplus energy Bonneville has available to market in the spring and summer. Bonneville estimates that the impact of operating the Federal System Hydroelectric Projects in conformance with the biological opinions and the Council's Fish and Wildlife Program, as in effect as of the beginning of Fiscal Year 2000, decreased Federal System hydroelectric 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. See "—General" immediately 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 annual 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 operations of the Federal System Hydroelectric Projects, Bonneville's fish and wildlife costs, inclusive of Direct Costs and Operational Impacts, rose to $399 million in Fiscal Year 1995. Annual fish and wildlife costs borne by Bonneville in recent fiscal years are described immediately above in "—General." Actions under the ESA affect other costs that Bonneville bears, including mitigation activities such as hatchery programs, which costs are included in the Council's Fish and Wildlife Program, discussed below. Bonneville is also continuing to provide funding under agreements with certain tribes and the states of Idaho, Montana, and Washington, including through updates and extensions to the Columbia Basin Fish Accords. See "—The Columbia Basin Fish Accords and Related Agreements," below.

Description of the 2014 Columbia River System Supplemental Biological Opinion and the 2020 Columbia River System Biological Opinions. As noted herein, litigation challenging the 2014 Columbia River System Supplemental Biological Opinion resulted in a determination, by the District Court, that it did not meet the requirements of the ESA or NEPA. See "BONNEVILLE LITIGATION—Columbia River ESA Litigation." The District Court directed that the Corps and Reclamation continue to implement the 2014 Columbia River System Supplemental Biological Opinion until issuance of a new environmental impact statement and biological opinion.

Since the 2014 Columbia River System Supplemental Biological Opinion expired of its own terms and the agreed to spring spill operations modified the federal agency action in a way not considered in the 2014 Columbia River System Supplemental Biological Opinion, the Action Agencies reinitiated consultation with NOAA Fisheries in 2018. The Action Agencies' proposed action was largely a continuation of the actions from the 2008-2018 time period, including tributary habitat improvement actions, estuary habitat measures, hatchery mitigation measures, predation management, and research and monitoring actions. An interim NOAA Fisheries biological opinion was effective on April 1, 2019 to cover operations and maintenance of the Columbia River System until the 2020 Columbia River System Biological Opinions were implemented in September 2020.

The Final CRSO EIS, issued on July 31, 2020, included the 2020 Columbia River System Biological Opinions. On September 28, 2020, Bonneville and the other Action Agencies issued the CRSO EIS Record of Decision adopting the Preferred Alternative in the Final CRSO EIS as the Selected Alternative (the "Selected Alternative") and implementing the consistent action consulted upon in the biological opinions. The 2020 Columbia River System Biological Opinions evaluated impacts of the Action Agencies' proposed action, which is consistent with the Selected Alternative, on 13 species of salmon and steelhead along with other species listed under the ESA and found that the Selected Alternative is not likely to jeopardize the continued existence of the ESA-listed species or destroy or adversely modify their designated critical habitat.

The Action Agencies considered six alternative courses of action and studied the environmental, economic and social impacts of such alternatives. The range of alternatives considered included a No Action Alternative and an alternative that included breaching the four lower Snake River dams. Dam breaching was not included as part of the Selected Alternative and it is the opinion of the General Counsel to Bonneville that breaching or other similar major structural changes eliminating one or more of the congressionally authorized purposes of any of the federal dams of the Federal System would require Congressional enactment authorizing such action.

The Selected Alternative results in a reduction of 160 annual average megawatts of hydropower generation from the Columbia River System projects relative to the No Action Alternative; however, an equivalent level of reduction in hydropower generation was implemented under the 2019-2021 spill operation agreement. See "BONNEVILLE LITIGATION—Columbia River ESA Litigation." Under the Selected Alternative, the Federal System overall is estimated to lose approximately 300 annual average megawatts of firm power available for long-term, firm power sales to Preference Customers under critical water conditions compared to the No Action Alternative; however, due to the seasonal shape of generation changes (less generation in spring, slightly more in winter and late August) the Regional power system reliability will be roughly the same as under current operations and no replacement resources are expected to be needed for reliability.

As part of stay negotiations in the Columbia River System litigation in 2021, the Action Agencies agreed to specific changes to planned 2022 fish passage operations. Bonneville evaluated the effects of these operational changes and found there would be minimal change in effects compared to the Selected Alternative. Under average water conditions, 2022 fish passage operations were expected to reduce the annual average megawatts of hydropower generation from the Columbia River System projects as compared to the Selected Alternative by 45 annual average megawatts. The parties subsequently agreed to 2023 fish passage operations, which are similar to those in effect for 2022 fish passage operations. In December 2023, the Biden Administration announced the December 2023 Agreement, an agreement to work in partnership with Pacific Northwest tribes and states to further the restoration of native fish populations, expand tribally sponsored clean energy production, and provide stability for communities that depend on the Columbia River System. The operations subject to the December 2023 Agreement are also similar to the effects for the 2022 and 2023 fish passage season, with the addition of the earlier start of both March surface spill operations, which will have a minor impact on available generation, and the summer spill reduction, which is likely to lead to more available generation in August than recent operations.

In addition to estimated impacts on hydropower generation, the Selected Alternative also includes certain structural modifications to Federal System hydroelectric dams. Amounts needed for construction of the structural modifications would be provided to the Corps and Reclamation either through direct funding or appropriated by Congress to the Corps or Reclamation (primarily related to the Columbia River Fish Mitigation program) and capitalized and recovered in Bonneville's rates over a period of 50 years.

Bonneville's authority to enter into the December 2023 Agreement is being challenged in court. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Developments Relating to the Endangered Species Act," and "BONNEVILLE LITIGATION—Columbia River ESA Litigation."

Impacts on Bonneville's Rates. In developing the Final 2024-2025 Rates, Bonneville made certain assumptions of the expected incremental costs that would arise from implementation of the 2020 Columbia River

System Biological Opinions to assure full cost recovery in Bonneville's rates. Bonneville's proposed power rates include, and its power rates for the past several rate periods have included, certain rate level adjustment provisions that enable Bonneville to increase rate levels within a rate period when Power RAR levels fall below certain cash on hand thresholds. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Proposed Bonneville Power and Transmission Rates Developments for Fiscal Years 2026-2028" and "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Power Rates for Fiscal Years 2024-2025."

The National Environmental Policy Act and the Endangered Species Act. NEPA requires that federal agencies evaluate the environmental impacts of their proposed actions and make this analysis available to the public. NEPA is procedural in the sense that it does not require a particular outcome for a decision, but it does mandate a process for taking a "hard look" at environmental consequences of, and alternatives to, an agency's proposal. Depending on the circumstances, NEPA may require that the federal government prepare an environmental impact statement prior to making a decision to undertake an action. Preparation of an environmental impact statement can be time consuming and the associated analysis can be extensive, depending on the complexity of the proposed actions and the potential effects on the environment.

The Columbia River Fish Mitigation Program. As noted above, the Action Agencies are currently implementing actions consistent with the 2020 NOAA Fisheries Columbia River System Biological Opinion. The 2020 NOAA Fisheries Columbia River System Biological Opinion carries forward from prior biological opinions plans for completion of structural modifications to Federal System hydroelectric dams. These modifications have been and are expected to be funded by specific federal appropriations, primarily to the Corps under the "Columbia River Fish Mitigation" program. Bonneville expects that it will be responsible for recovering in its power rates as a repayment to the United States Treasury approximately 80 percent of the costs of the federally appropriated modifications to the Federal System Hydroelectric Projects on the Columbia River and Snake River, 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, for 50 years in most cases, from the dates the related capital facilities are placed in service or the regulatory asset is completed. These studies and modifications have been funded over many years; thus, their costs have been and will be gradually added to Bonneville's rates and statutory repayment obligations that Bonneville has for amounts appropriated by Congress for federally-owned hydroelectric and transmission facilities of the Federal System ("Federal Appropriations Repayment Obligations") as they are completed and placed in service.

As of the end of Fiscal Year 2024, Bonneville was responsible for approximately $1.1 billion of Columbia River Fish Mitigation costs, as allocated to the power purpose of the Corps' Federal System Hydroelectric Projects. Under the Corps' current plan covering five years, the Columbia River Fish Mitigation program would obtain additional appropriations for continued funding of modifications and increase the amount expected to eventually be assumed by Bonneville as repayable appropriations obligations by approximately $123 million through Fiscal Year 2029. This would bring the total amount of Bonneville's Federal Appropriations Repayment Obligations for Columbia River Fish Mitigation to approximately $1.2 billion by the end of Fiscal Year 2029. The amounts ultimately appropriated under the Columbia River Fish Mitigation program (through Fiscal Year 2029 and in future years) may be greater depending on possible changes to the Corps' current five year plan, the Corps' plans for years beyond Fiscal Year 2029, requests for appropriations by the Corps and Congressional enactments of appropriations. The expected costs associated with such additional Federal Appropriations Repayment Obligations for Columbia River Fish Mitigation will begin to be recovered in Bonneville's power rates when the related investments are placed in service, which depends on the timing and amounts of appropriations and the time required by the Corps to bring multi-year projects to completion. Other federally appropriated amounts may be added to Bonneville's Federal Appropriations Repayment Obligations from time to time depending on specific project appropriations received by the Corps and Reclamation for Federal System investments. See "BONNEVILLE FINANCIAL OPERATIONS—The Federal System Investment."

Bonneville is unable to predict the effects, if any, that the 2020 NOAA Fisheries Columbia River System Biological Opinion will have on the types and timing of Federal System investments (including but not limited to investments under the Columbia River Fish Mitigation program) for which Congressional appropriations will be requested and enacted, the amounts appropriated therefor, and the amounts that would be included for recovery in Bonneville's rates for power. See "BONNEVILLE FINANCIAL OPERATIONS—The Federal System Investment."

The Columbia Basin Fish Accords and Related Agreements. Beginning in 2008, Bonneville, the Corps, and Reclamation entered into seven separate agreements with a number of parties including six tribes, an inter-tribal association, and the states of Washington, Montana and Idaho. These agreements, collectively known as the Columbia Basin Fish Accords, assured long-term mitigation funding to address Federal System Hydroelectric Projects' effects on fish and wildlife, and have helped the Action Agencies protect, mitigate, and enhance fish and wildlife in the Columbia River basin and address the Action Agencies' responsibilities for ESA-listed fish.

Bonneville's funding commitments under the Columbia Basin Fish Accords have been and will be for work necessary to implement actions associated with biological opinions for the Federal System Hydroelectric Projects and for work that otherwise addresses federal statutory fish and wildlife mitigation responsibilities such as those under the Northwest Power Act.

Certain of the agreements comprising the Columbia Basin Fish Accords have been amended and extended several times. Bonneville's total remaining commitment through 2034 for the Columbia Basin Fish Accords is approximately \$809 million. This total includes approximately \$502 million in remaining commitments from the prior agreements expiring in 2025 and \$306 million in additional commitments for the Fiscal Years 2024 through 2034. For details related to the current total outstanding Columbia Basin Fish Accords and similar commitments, see Appendix B-1 to the Official Statement (Note 14 to Financial Statements).

The commitments above include the pre-existing Columbia Basin Fish Accords commitments as well as two new agreements. Bonneville entered into new agreements with the Coeur D'Alene Tribe and the Spokane Tribe of Indians. Bonneville's commitment under these agreements is approximately \$163 million and \$148 million respectively, through Fiscal Year 2033. Additionally, at the beginning of Fiscal Year 2025, Bonneville also signed a new Accord agreement with the Kalispel Tribe of Indians committing an additional \$89 million through Fiscal Year 2034. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Developments Relating to the Endangered Species Act," and "BONNEVILLE LITIGATION—Columbia River ESA Litigation."

The Columbia Basin Fish Accords do not include long-term funding arrangements relating to wildlife mitigation in the Willamette basin and northern and southern Idaho.

Bonneville is unable to provide any certainty regarding the costs it may incur, including from possible future changes in Federal System dams or dam operations, under the ESA or other environmental laws.

Willamette River Basin. The Corps owns and operates 13 dams in the Willamette River Basin (the "Willamette Project") for the purposes of flood risk reduction, hydropower (at eight dams), recreation, and water supply. The Willamette Project is included in the Federal System. Bonneville markets the power from the Willamette Project and funds the Corps for the power purpose share of both capital and operations and maintenance costs at the facilities of the Willamette Project. Bonneville estimates that, prior to recent litigation described below, approximately 197 megawatts of power were produced by the Willamette Project under average water conditions. In December 2020, Congress directed the Corps to study de-authorization of the power purpose at three Willamette dams (Big Cliff, Cougar, and Detroit). In December 2022, Congress directed the Corps to complete a disposition study of the power purpose at the Willamette Project no later than June 2024. The Corps has not yet made any findings available for public review related to the 2020 or the 2022 studies. As part of the provisions for the 2022 disposition study, Congress provided that, until the report is issued, Bonneville shall not reimburse the Corps for new construction-related expenditures for the Willamette Project. If a decision were made to seek de-authorization of the power purpose at any of the Willamette Project dams, Congress would need to pass legislation authorizing such action.

Willamette River Basin Flood Control Project Biological Opinion. In 2008 NOAA Fisheries issued its Willamette River Basin Flood Control Project Biological Opinion (the "2008 Willamette biological opinion"). The 2008 Willamette biological opinion evaluated the impact of ongoing operations of the Willamette Project on fish species that are listed under the ESA as threatened or endangered, and concluded that certain species were in jeopardy and their critical habitat was likely to be adversely modified or destroyed. The 2008 Willamette biological opinion was also adopted in a separate biological opinion by the Fish and Wildlife Service.

To fulfill the requirements of the 2008 Willamette biological opinion related to downstream passage and water temperature control, the Corps first instituted a variety of operational changes and, after securing funding, modified or constructed a host of facilities. The Corps also carried out a multi-year, multi-level study process, known as the Configuration and Operation Plan or "COP," to evaluate a range of potentially beneficial actions for listed fish species at Willamette dams and reservoirs, including for long-term downstream passage and temperature control. The results of the COP provided a plan of action for potential downstream fish passage facilities at Cougar and Detroit dams (and temperature control at Detroit dam). These facilities were not constructed at that time.

On March 13, 2018, three environmental protection organizations filed an action against the Corps and NOAA Fisheries in the District Court with respect to operation and maintenance of the Willamette Project related to decision making, hatcheries, downstream passage, and water quality. Specifically, the plaintiffs sought reinitiation of consultation under Section 7 of the ESA, in part due to the Corps' failure to construct the fish passage facilities contemplated in the 2008 Willamette biological opinion, which could result in changes to or replacement of action items that could further increase costs to Bonneville. After numerous court hearings on various motions, the District Court issued a draft order on July 14, 2021, ordering injunction measures to be refined with the input of an expert panel. The proposed injunction measures included fall/winter reservoir drawdowns at Cougar, Green Peter, Look Out, and Fall Creek dams; fish passage and water quality operations at several projects; and spill operations. A final order was issued by the District Court on September 1, 2021, adopting the remedy measures contained in the draft order and finalizing the composition of the expert panel, a mix of federal and plaintiff experts. In the final order, the District Court also held that the Corps has the authority to eliminate the reserved power pool (reservoir elevations at Willamette Project dams reserved for power generation during the months of October through April) to benefit ESA-listed fish species.

The federal government began implementing court-ordered measures in November 2021. Among them are an operation to withdraw water through non-power outlets at Detroit Dam and a draw down at Cougar Dam, which eliminate most or all electricity generation in fall and winter months. Delayed refill in the spring greatly diminished power generation at Cougar Dam in the spring of 2022 and is expected to have a similar impact in subsequent years. Similar reservoir drawdowns occurred at Look Out Point Dam and Green Peter Dam in the fall of 2023. In aggregate, implementation of all of the court-ordered measures is expected to reduce the total electricity generated at the Willamette Project by about one-third.

The Corps, Bonneville and Reclamation reinitiated consultation with NOAA Fisheries and the Fish and Wildlife Service in April 2018 on new biological opinions. The Corps concurrently initiated a new environmental analysis under NEPA on a Programmatic Environmental Impact Statement to address the continued operations and maintenance of the Willamette Valley System (the "Willamette EIS"), which the Corps finalized and published in the Federal Register on April 11, 2025. A supplement to the Willamette EIS analyzing a non-hydropower alternative for Willamette Valley System operations, in compliance with the Water Resources Development Act of 2024, is expected to be finalized and published in 2026. The fish passage facilities which were contemplated in the 2008 Willamette biological opinion but not constructed are now included as a suite of projects evaluated in the Willamette EIS. NOAA Fisheries issued its new biological opinion on December 31, 2024. A new Willamette biological opinion from the Fish and Wildlife Service currently remains in progress.

Under Bonneville's existing appropriations repayment criteria, after any proposed structural modifications are placed in service, it is expected that a portion of the amounts appropriated for such purposes will be included in Bonneville's Federal Appropriations Repayment Obligation for recovery in Bonneville's rates. The proportion of the overall Willamette Project's fish mitigation costs that are assigned to be recovered in Bonneville's power rates is approximately 42 percent. Under the applicable repayment criteria, the costs, which include study, design, and construction costs, would be recovered in Bonneville's rates over a period of 75 years from the dates that related modifications are placed in service.

Bonneville expects there to be an increase in the all-in costs of the Willamette Project power, which include but are not limited to fish mitigation measures such as streamflow enhancements and fish habitat/hatchery improvements under the new biological opinions. The forthcoming biological opinion from the Fish and Wildlife Service could result in additional operational changes, or other measures. Although Bonneville can make no prediction of the total costs or consequences to it with respect to the Willamette Project arising under the ESA, Bonneville intends to mitigate any upward rate pressure, to the extent possible, through offsetting cost reductions in other Bonneville programs.

Willamette River Basin Memorandum of Agreement Regarding Wildlife Habitat Protection and Enhancement. Bonneville and the State of Oregon signed an agreement in 2011 that, upon successful completion, permanently fulfills Bonneville's longstanding wildlife mitigation obligations under the Northwest Power Act associated with the Willamette River dams. Bonneville's total commitment under the agreement is $144 million (including inflation) through Fiscal Year 2025. In addition, Bonneville will provide some level of additional funding for the Oregon Department of Fish and Wildlife's operations and maintenance costs with respect to the Willamette Project for Fiscal Year 2026 through Fiscal Year 2043. Bonneville will negotiate its funding obligations based on historical funding levels and contemporaneous needs and conditions.

<u>Federal Repayment Offsets For Certain Fish and Wildlife Costs Borne by Bonneville</u>. In 1995, the United States Treasury, the OMB, 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 the Federal System Hydroelectric 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 $112 million, $258 million, and $258 million in Fiscal Years 2022, 2023, and 2024, 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 hydroelectric output of the Federal System is lower and market prices for power may be comparatively high. In such years, 4(h)(10)(C) credits are correspondingly higher.

<u>Council's Fish and Wildlife Program</u>. In 2015, the Council amended the Columbia River Basin Fish and Wildlife Program (the "Council's Fish and Wildlife Program") to recommend actions to mitigate the impacts of the operation of the hydroelectric dams of the Federal System on fish and wildlife in the Region, as provided under the Northwest Power Act. In general, Bonneville is charged with protecting, mitigating, and enhancing fish and wildlife affected by the Federal System in a manner consistent with the Council's Fish and Wildlife Program, the Council's Power Plan, and the other purposes of the Northwest Power Act. The Council's Northwest Power Act mitigation recommendations include the actions in the Columbia Basin Fish Accords and biological opinions as well as other measures to protect fish and wildlife. The Council amended its fish and wildlife program in the fall of 2020. The amendment was largely intended to clarify, reorganize and supplement the program, but not amend or replace the existing program.

In view of the increasing number of actions under the ESA in connection with listed fish populations affected by the Federal System, and in view of the potential for overlap or conflict of ESA-related actions with recommendations under the Council's Fish and Wildlife Program, beginning in the late 1990s, the Council began integrating ESA and Clean Water Act compliance actions into the Council's Fish and Wildlife Program. The costs of this "Integrated Program" are included in the Direct Costs to Bonneville of its fish and wildlife obligations. See "—General." In Fiscal Year 2024, Integrated Program expense was $297 million, and Federal System capital investment was $28 million. Bonneville forecasts that Fiscal Year 2025 Integrated Program expense and Federal System capital investments will be $330 million and $59 million, respectively.

Bonneville believes its current levels of funding fulfill all of its statutory responsibilities related to fish and wildlife; however, Bonneville cannot provide assurance as to the scope or cost of future measures to protect fish and wildlife affected by the Federal System Hydroelectric Projects (and other components of 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 2024-2025

As described elsewhere in this Appendix A, Bonneville prepared and filed with FERC Bonneville's Final 2024-2025 Rates for power and transmission rates of general applicability and FERC has granted final approval thereof. The final Tier 1 PF Rates for the 2024-2025 Rate Period for power sold to Preference Customers for their requirements vary depending on the particular power product provided by Bonneville. Average base Tier 1 PF Preference Rates (inclusive of the Slice, Block and Load Following products) decreased by less than one percent from the prior average rates to $34.69 per megawatt hour. Under the Final 2024-2025 Rates, average Tier 2 PF Rates (which apply to certain incremental loads that Preference Customers require Bonneville to meet) increased by 83 percent, to $61.50 per megawatt hour when compared to Average Tier 2 PF Rates in effect in the prior rate period. For additional details regarding Tier 1 PF Rates and Tier 2 PF Rates, see "—Bonneville's Obligation to Meet Certain Firm Power Requirements in the Region—Comparison of Tier 1 PF Rates and Tier 2 PF Rates."

The Final 2024-2025 Rates continue use of a CRAC. The CRAC mechanisms implemented in the Final 2024-2025 Rates are similar to the CRAC for the 2022-2023 Rate Period. An increase in power rate levels under the CRAC would occur if certain financial information resulted in Power Services' expenses that were higher and/or revenues that were lower than anticipated that resulted in Power Services' RAR falling below certain thresholds as of September 30.

The CRAC enables Bonneville to increase certain power and related rate levels over base rates to obtain up to $300 million in additional revenue in each of the two fiscal years of the rate period, without a time-consuming rate proceeding, if Power Services' RAR are below zero at the beginning of either fiscal year in the rate period. The amount of additional revenue to be obtained under the CRAC in a fiscal year would be established, in general, to be the amount of the difference between zero and the Power Services' RAR at the beginning of the fiscal year in which the CRAC is evaluated for implementation (this differential is referred to herein as the "CRAC Underrun"). More particularly, the CRAC would be used to obtain in a fiscal year: (i) all of the first $100 million of a Power CRAC Underrun, if any, for such fiscal year, and (ii) one half of any remaining Power CRAC Underrun for such fiscal year, up to a maximum of $200 million. Such amounts would be reduced by the amount of planned revenue financing, if any, for such fiscal year. The CRAC terms include a *de minimis* provision under which Bonneville would not trigger the CRAC for implementation for a fiscal year unless the CRAC Underrun were to exceed $5 million.

Also included in the Final 2024-2025 Rates, Power Services rates continue to make available a surcharge rate adjustment mechanism (the "FRP Surcharge") to implement Bonneville's Financial Reserves Policy and rate actions to raise RAR levels when they fall below a specified level for each business line. An increase in Power Services rate levels under the Financial Reserves Policy Surcharge would occur if Power Services' RAR falls below certain thresholds as of September 30. The thresholds for each business line are equivalent to the amount of cash needed to meet operating expenses for 60 days. For Power Services, the forecast amount of cash expected to be needed to meet its operating expenses for 60 days is $319 million. The Financial Reserves Policy Surcharge would allow Bonneville to increase certain power and related rates over base rates to obtain up to $40 million of additional revenue if Power Services' RAR were below $319 million at September 30, 2024. The FRP Surcharge terms include a *de minimis* provision under which Bonneville would not trigger the FPR Surcharge for implementation for a fiscal year unless the underrun were to exceed $5 million.

Neither a CRAC nor a Financial Reserves Policy Surcharge, included in the Final 2024-2025 Rates, triggered at September 30, 2023, for application to Fiscal Year 2024 power rate levels or at September 30, 2024 for application to Fiscal Year 2025 power related rate levels.

The Final 2024-2025 Rates for Power Services continue the availability of the RDC, which has triggered for application to certain power rates and transmission rates in Fiscal Year 2024. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Current Bonneville Power and Transmission Rates" and "TRANSMISSION SERVICES—General—Bonneville's Transmission and Ancillary and Control Area Services Rates." Bonneville's decision regarding application of the Fiscal Year 2023 Power RDC is being challenged in court. See "BONNEVILLE LITIGATION—Fiscal Year 2023 Power RDC Challenge."

Under the Final 2024-2025 Rates, Bonneville also reserved the ability to institute another full rate proceeding and increase rates or rate levels in the rate period, which Bonneville has estimated would take several months.

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

Historical PF Preference Rate Levels

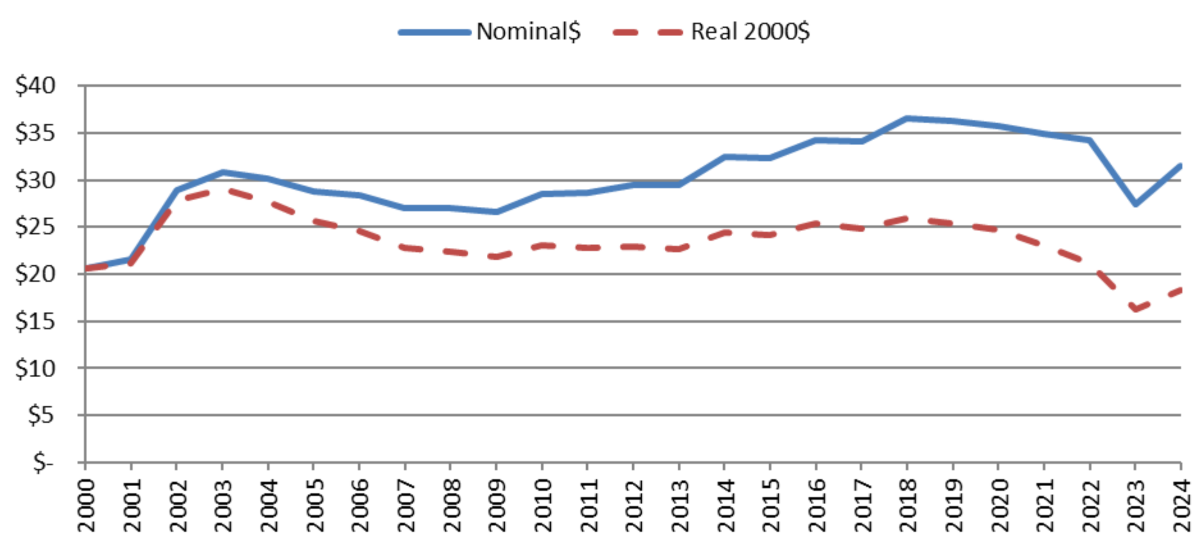
As shown in the following chart, Bonneville's average PF Preference Rates have remained between $20 per megawatt hour and $37 per megawatt hour in nominal (actual) dollars, and between $16 per megawatt hour and $29 per megawatt hour in inflation-adjusted (real) dollars (2000), from Fiscal Year 2000 to Fiscal Year 2024. These estimates include average PF Preference Rates expressed on a dollar-per-megawatt-hour basis, exclusive of Slice rates. While most PF Preference Rates are established on a dollar-per-megawatt hour basis, Slice rates are set on the basis of dollars-per-percentage-point of Slice. The data also exclude PF Exchange Rates which are used in determining Residential Exchange benefits, and Tier 2 PF Rates, which Bonneville instituted in Fiscal Year 2012 to recover the cost of meeting certain incremental loads.

Bonneville's average PF Preference Rates increased substantially in Fiscal Year 2002 to recover costs incurred during and as a result of the West Coast energy crisis in 1999-2001. Since then, such rates have been stable, especially when viewed from an inflation-adjusted perspective, as shown in the following chart.

Historical Average PF Preference Rates

Nominal (Actual) and Real (Inflation-Adjusted) Average PF Preference Rate Levels,

Per Megawatt Hour, Fiscal Years 2000—2024



Recovery of Stranded Power Function Costs

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

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

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

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

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

TRANSMISSION SERVICES

Bonneville provides a number of different types of transmission services to Preference Customers, Regional IOUs, DSIs, other privately and publicly owned utilities, power marketers, power generators, and others. Transmission Services earned approximately $1.2 billion in revenues from the sale of transmission and related services, or approximately 27 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 2024.

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

It is difficult to generalize as to a Preference Customer's cost of Network Integration service needed to effect various power transactions because the charge is based on actual usage and thus can vary from month to month and customer to customer. Nonetheless, a useful point of reference for the proportion that power rates bear to transmission and ancillary services rates may be the cost borne by certain Preference Customers that purchase Full Requirements power from Bonneville. For example, in the current rate period (Fiscal Years 2024-2025), a large Preference Customer that purchases very little transmission for its own generating resources pays Bonneville approximately $4.74 per megawatt hour for transmission service and approximately $34.69 per megawatt hour for electric power (excluding the effect of any rate adjustment mechanisms).

Bonneville's Federal Transmission System

The Federal System includes the Federal Transmission System, which is operated and maintained by Bonneville and owned or leased by Bonneville, as well as the Federal System 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 259 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 a main-grid network for service within the Pacific Northwest, and approximately 80 percent of the northern portion (north of California and Nevada) of the combined Southern Intertie, the primary bulk transmission link between the Pacific Northwest and the Pacific Southwest. The Southern Intertie consists of three high voltage Alternating Current ("AC") transmission lines and one Direct Current ("DC") transmission line and associated facilities that interconnect the electric systems of the two regions. The rated transfer capability of the Southern Intertie AC in the north to south direction is 4,800 megawatts of capacity, and in the south to north direction is 3,675 megawatts of capacity. The rated transfer capability of the DC line in the south to north direction is 3,100 megawatts, and in the north to south direction is 3,220 megawatts.

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. 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, wildfire and other natural disasters, and changes in generation and load patterns may reduce the reliable 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 entities seeking new transmission service in the Region. In recent years, many of the requests for new or increased transmission service have been submitted by customers seeing large load growth and customers developing new power generation projects, primarily wind and solar generation, both inside and outside the Region. As reflected in the 2026-2028 Initial Rate Proposal (and Fiscal Year 2025 year-end forecast as of December 31, 2024 for Fiscal Year 2025), Bonneville expects to make transmission system investments in Fiscal Years 2025 through 2034 averaging approximately $1,004 million annually. See "BONNEVILLE FINANCIAL OPERATIONS—Bonneville's Capital Program" and "—Bonneville's Non-Federal Debt." Such amounts include moving forward with over $2 billion of the expected $5 billion in electricity grid improvement investments expected to occur through Fiscal Year 2039 referred to as the "Evolving Grid Projects," that will significantly increase the capacity and reliability of the Pacific Northwest grid and its ability to integrate new loads and energy sources. The Evolving Grid Projects include 23 strategic capital projects needed across Bonneville's service territory to eliminate chokepoints, expand load service, and enable new generation projects' access to Bonneville's Transmission system and neighboring states' utilities to market their production. Projects will increase transmission capacity by up to 6 gigawatts, enough to power about 4.5 million homes and help meet growing demand for more affordable power.

If a customer requests to interconnect a new power generation project to the Federal Transmission System, Bonneville uses a process to analyze the request to determine whether and to what extent it needs to construct additional facilities to accommodate the request. In Fiscal Year 2023, Bonneville started a proceeding to improve the efficiency of this process. In Fiscal Year 2024, Bonneville issued a final record of decision related to reforms to allow Bonneville to more efficiently process generator interconnection requests and connect new larger generators onto the Federal Transmission System. These reforms include replacing the first-come, first-served serial process for processing large generator interconnection requests with a first-ready, first-served cluster study process. These reforms are intended to help more efficiently allocate Bonneville's resources to manage the study process, address the backlog of requests, and mitigate study delays. In Fiscal Year 2025, Bonneville began transitioning to the new process. When 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 interconnection. If the necessary facilities are integrated into Bonneville's network, Bonneville returns to the customer the amounts it advanced for construction of the new facilities (plus interest earned on outstanding balances) in the form of (i) credits against the customer's monthly bills for firm transmission service, or (ii) in some cases, cash payments to the generator or its assigns. The transmission service credit offsets for amounts advanced to Bonneville for new interconnection investments were $22 million in Fiscal Year 2024. Bonneville estimates that the transmission service credit offsets for amounts advanced to Bonneville for new interconnection investments will be $27 million in Fiscal Year 2025 and approximately $43 million in Fiscal Year 2026.

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

Bonneville studies and upgrades the Federal Transmission System to meet the Region's emerging commercial needs for expanded transmission service under its Tariff. For Network Integration service requests, Bonneville generally employs a cluster approach wherein it aggregates pending requests for transmission service in order to study and otherwise evaluate the new transmission facilities that it would have to construct to provide that service. Bonneville employs this process to help ensure that it will accurately identify plans of service for serving new requests, recover the costs of any new transmission facilities that are constructed, and avoid stranded transmission investments.

In Fiscal Year 2025, Bonneville began assessing its transmission system investment plan to improve efficiency and responsiveness to customers. Bonneville is unable to predict the cost of new investments for the interconnection of new generation or to meet customers' new transmission service requests, the amount of transmission that customers will actually commit to, or the extent to which Bonneville will fund such investments through customer advances of funds, borrowing from the United States Treasury, or Non-Federal Debt (that relates to various arrangements to meet Bonneville's capital program which involve debt issued by third parties, the repayment of which is secured by Bonneville financial commitments), such as lease-purchases. For a discussion of the applicability of FERC's cost allocation methodology under Order 1000 (as hereinafter defined), see "—Bonneville's Participation in Regional Transmission Planning."

Federal Transmission System Management for Fire Hazard

Operating the Federal Transmission System poses various risks, including the risk of fire hazard that could result in widespread electric power outages, property damage, personal injury, or death. Bonneville has implemented and employs an integrated vegetation management program that complies with the North American Electric Reliability Corporation Standard FAC-003 to help ensure that its transmission lines remain free and clear of brush and trees and that trees and vegetation are a safe clearance distance so that vegetation will not come into contact with Bonneville's transmission lines under any operating conditions. The vegetation management program is integrated in Bonneville's asset management and vegetation management strategies and refreshed every two years.

Bonneville's vegetation management program relies on a cohesive group of experts who manage the vegetation on and around Bonneville's 15,000 miles of transmission lines on 8,500 miles of rights-of-way and facilities, such as substations, switchyards and microwave/radio sites in the Pacific Northwest. Bonneville employs natural resource specialists and foresters who use ground and helicopter patrols to identify vegetation that could threaten Bonneville's transmission lines, including by encroaching on minimum vegetation clearance distances. Bonneville also utilizes light detection and ranging (LIDAR) in some instances to identify trees and vegetation within and adjacent to Bonneville's rights-of-way that may impinge clearance distances or otherwise interfere with grid reliability. Bonneville is recognized as a right-of-way steward utility by the Right-of-Way Stewardship Council, which is an accreditation program that establishes standards for responsible right-of-way vegetation management and promotes best practices for maintaining power system reliability and addressing ecological concerns.

Additionally, a regular integrated vegetation maintenance cycle and clearing on easements helps keep transmission corridors clear of fuel for wildfires. To perform this work, Bonneville contracts vegetation clearing crews that comply with all applicable laws and regulations pertaining to fire prevention. They carry firefighting equipment, use chainsaws with spark arresters and provide a fire watcher when necessary. The contract crews manage the debris to minimize fire hazards by cutting, lopping and scattering branches, which disperses the potential fuel and maximizes the contact with the ground to promote decomposition. The natural resource specialists developing the annual work plan consider the risk of fire and the environmental restrictions associated with threatened and endangered species.

In the spring of 2020, Transmission Services released its original Wildfire Mitigation Plan to prevent Bonneville transmission lines and other assets from sparking wildfires, and to protect Bonneville lines and assets from the threat of wildfires. The Wildfire Mitigation Plan was updated in 2021 to add a Public Safety Power Shutoff procedure (the "PSPS"). The PSPS is proactive de-energization of transmission lines and facilities due to extreme weather (i.e., high winds) and other environmental conditions (i.e., low relative humidity and extremely dry fuels) designed to further protect homes, businesses, property and emergency responders from the devastating effects of wildfires.

In September 2020, the Region's typical hot and dry August weather conditions were very quickly followed by a rare, early September dry wind storm with gusts as high as 70 miles per hour, creating a scenario for the extreme wildfire activity witnessed across Bonneville's service territory. Transmission equipment in seven of Bonneville's 13 transmission maintenance districts were impacted by the wildfires. While the majority of Bonneville's response was centered in northeastern Washington State and the Eugene and Salem, Oregon areas of its service territory, field crews from 10 Bonneville districts assessed, monitored and worked with dispatch to de-energize and re-energize lines in response to the needs of customers and fire fighters.

In all, Bonneville, at some point, had 38 transmission lines out of service due to the wildfires. Some outages were due to wildfire damage. Others were removed from service so fire fighters could work on or near Bonneville rights-of-way, or to allow Bonneville crews to safely work on the transmission lines.

One of the wildfires, called the Holiday Farm Fire ("HFF"), resulted in claims for damage against the United States Government. To date, Bonneville has received over 2,000 administrative tort claims under the Federal Tort Claims Act ("FTCA") related to the HFF totaling approximately $2 billion in aggregate damages. These claims resulted in three separate suits filed in January and February of 2024 in the U.S. District Court of Oregon. Tort claims must be brought against the United States —and not Bonneville—under the FTCA and all settlements or court judgments from tort claims are paid by the United States Judgment Fund, not the Bonneville Fund. See "MATTERS RELATING TO POWER SERVICES AND TRANSMISSION SERVICES—Limitations on Suits against Bonneville."

On December 12, 2023, the U.S. Department of Justice was served with an inverse condemnation claim related to the same wildfire event. Plaintiffs assert that the HFF resulted in a taking of their property without just compensation that is compensable under the 5th Amendment of the United States Constitution. Bonneville is unable to predict with certainty whether any settlements or judgments arising from this suit would be paid from the United States Judgment Fund or the Bonneville Fund. Although Bonneville does not have a track record with source of payment for any past inverse condemnation settlements or judgments, similar suits against other federal agencies have been paid from the Judgment Fund, and the United States Treasury has indicated the Judgment Fund would be available to pay settlements or judgments arising from this case. For more details related to these claims, see "BONNEVILLE LITIGATION—Holiday Farm Fire Litigation."

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

In 1996, FERC issued Order 888 to promote competition in wholesale power markets. Among other things, Order 888 established a *pro forma* tariff providing the terms and conditions for non-discriminatory open access transmission service, and required all public utilities (the utilities subject to FERC regulation, which does not include government entities such as Bonneville) to adopt the tariff. Order 888 also included a reciprocity provision under which jurisdictional utilities must grant open access transmission services to non-jurisdictional (i.e., unregulated) utilities if the non-jurisdictional utility offers open access in return. 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.

EPA-2005 authorizes FERC to require an "unregulated transmitting utility" (a term that includes Bonneville) to provide transmission services to others (i) at rates that are comparable to those that the utility charges itself, and (ii) 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."

Although Bonneville is a non-jurisdictional utility and is not subject to FERC Orders 888 and 890, since 1996, Bonneville has maintained terms and conditions for a non-discriminatory open access transmission tariff that is modeled after FERC's *pro forma* tariff. Bonneville follows the procedures in Section 212(i)(2)(A) of the FPA to make changes to the tariff. Section 212(i)(2)(A), added to the FPA by EPA-1992, provides the Administrator with the option to initiate a regional hearing to adopt transmission terms and conditions of general applicability. The regional hearing largely follows Bonneville's rate case procedures (e.g., opportunities to present oral and written views on the record). The Administrator may also use these procedures for FERC ordered transmission services under EPA-1992.

FERC issued Order 889 in 1996 and Order 717 in 2008. Each order sets forth FERC's Standards of Conduct ("SOC") for jurisdictional transmission providers that have a power marketing affiliate or function. In general, these SOC 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 a non-jurisdictional utility and is not subject to Orders 889 and 717, Bonneville has adopted and follows an SOC policy.

General - Bonneville's Transmission and Ancillary and Control Area Services Rates

Under the Northwest Power Act, Bonneville's Transmission Services 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 confirms and approves Bonneville's transmission rates after a finding that such rates recover Bonneville's costs during the rate period, and are sufficient to make full and timely payments to the United States Treasury, and, as to Transmission Services rates, equitably allocate the costs of the Federal Transmission System between federal and non-federal power utilizing the system.

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

The Final 2024-2025 Rates for Transmission Services reflect no change from the average rates in effect in the prior rate period. The Final 2024-2025 Rates for Transmission Services continue the availability of the RDC, which has triggered for application to Fiscal Year 2025 Transmission Services rates. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Current Bonneville Power and Transmission Rates."

Transmission Services' Largest Customers

The following table lists Transmission Services' ten largest customers in terms of their percentage contribution to Transmission Services' overall sales revenue in Fiscal Year 2024. The table also notes the type of entity for each customer.

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Transmission Services' Ten Largest Customers By Sales[1]
(Percentage of Transmission Services' Sales Revenue in Fiscal Year 2024)

Customer Name (Class)	Approximate % of Sales
Puget Sound Energy Inc. (Regional IOU)	13%
Powerex Corp. (Power Marketer)	9%
PacifiCorp (Regional IOU)	9%
Portland General Electric Company (Regional IOU)	9%
City of Seattle, City Light Dept. (Preference Customer)	5%
Snohomish County PUD No. 1 (Preference Customer)	5%
Avangrid Renewables, LLC (Wind Developer)	4%
Umatilla Electric Cooperative (Preference Customer)	4%
Morgan Stanley Capital Group Inc. (Power Marketer)	3%
Pacific Northwest Generating Cooperative (Preference Customer)	3%

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

Bonneville's Participation in Regional Transmission Planning

Bonneville has long participated in Regional transmission planning. This is evidenced by its participation in "NorthernGrid," which includes 13 member utilities across the Northwest and some Rocky Mountain states. NorthernGrid is not a Regional Transmission Organization ("RTO") under FERC policies. In addition to NorthernGrid's coordinated planning, Bonneville continues to explore opportunities to address Regional and inter-regional transmission planning needs by engaging in Western Power Pool's Western Transmission Expansion Coalition ("WestTEC") initiative to explore west-wide transmission planning. WestTEC is a voluntary planning effort that does not address cost allocation.

In Order 890, FERC provided direction regarding principles for open, coordinated transmission planning on a Regional level. Subsequent to its "Order 890" reforms, FERC provided transmission planning and cost allocation direction in its "Order 1000." Order 1000 requires jurisdictional utilities to participate in certain Regional and interregional transmission planning processes and cost allocation methodologies for transmission projects. Cost allocation involves the mandatory (non-voluntary) contribution by utilities to the cost of the related transmission projects. Although Order 1000 does not apply to non-jurisdictional utilities such as Bonneville, FERC encourages non-jurisdictional utilities to participate by requiring compliance in order to obtain reciprocity and by indicating that it might exercise its authority under FPA section 211A to require such utilities to comply if they do not do so voluntarily.

NorthernGrid provides for coordination among its mixed jurisdictional membership by striking a balance between addressing FERC-compliance needs of jurisdictional utilities and the needs of non-jurisdictional utility members seeking to participate in FERC's planning reforms through a process that respects their unique legal obligations. Bonneville's participation in coordinated Regional planning at NorthernGrid does not include participation in Order 1000's cost allocation requirements. Thus, Bonneville participates in coordinated Regional planning without being subject to mandatory cost allocation, and it is not able to impose mandatory cost allocation of its proposed projects on other participating utilities. Bonneville does not intend to revisit its decision regarding its participation in the Order 1000 cost allocation reforms at this time.

In April 2022, FERC initiated a formal rulemaking proceeding to consider reforms to long-term regional transmission planning and cost allocation processes. The proposed reforms were not directed at non-jurisdictional utilities. In May 2024, FERC issued its "Order 1920," which is FERC's final transmission planning and cost allocation rule that builds on Order Nos. 888, 890, and 1000. Bonneville is in the process of coordinating with NorthernGrid members to evaluate Order 1920 with the expectation that the reforms will be treated in a manner that is consistent with the existing structure and governance in place at NorthernGrid. That is, similar to its approach to Order 1000, Bonneville expects to adopt the Order 1920 planning reforms through its tariff and coordinating agreements with NorthernGrid members, but it does not intend to adopt Order 1920's reforms relating to cost allocation.

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 contains numerous ratemaking directives and incorporates the provisions of other Bonneville organic statutes, including the Bonneville Project Act, the Transmission System Act and the Flood Control Act of 1944. The Transmission System Act requires, among other things, that Bonneville establish its rates "with a view to encouraging the widest possible diversified use of electric power at the lowest possible rates to consumers consistent with sound business principles," while having regard to recovery of costs and repayment to the United States Treasury. Substantially the same requirements are set forth in the Flood Control Act.

Bonneville Ratemaking Procedures

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

Federal Energy Regulatory Commission Review of Rates Established by Bonneville

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

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

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

Judicial Review of Federal Energy Regulatory Commission Final Decisions

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

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

Power Customer Classes

The Northwest Power Act, as well as other Bonneville organic statutes, provides for the sale of power: (i) to Preference Customers, regional federal agencies, and investor-owned utilities; (ii) to DSIs; and (iii) for those portions of loads which qualify as "residential," to investor-owned and public utilities participating in the Residential Exchange Program. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Residential Exchange Program." The rates for firm 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.

Surplus Energy

Bonneville is authorized to sell power that is surplus to meeting Bonneville's regional firm power sales obligation and seasonal surplus power both within and outside the Pacific Northwest. Many of these sales are to purchasers outside the region, primarily to California under short-term power sales that allow for flexible prices, or under long-term contract rates.

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 specify the types of actions, remedies available, procedures to be followed, and the proper forum. Any tort claims, including any tort claims related to the September 2020 wildfires (see "TRANSMISSION SERVICES—Federal Transmission System Management for Fire Hazard"), must be brought against the United States Government under the Federal Tort Claims Act. All settlements or court judgments from tort claims are paid by the Judgment Fund, not the Bonneville Fund. 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 a host of environmental laws to prevent and address environmental contamination related to its operations, including the Comprehensive Environmental Response, Compensation and Liability Act of 1980 ("CERCLA") and its state equivalents. Currently, there is one Superfund site (Portland Harbor Superfund Site) and one non-Superfund facility for which Bonneville has been identified by regulatory agencies as being a Potentially Responsible Party ("PRP") for some of the contamination. The United States Department of Justice is representing federal agencies, including Bonneville, in ongoing CERCLA mediation and settlement processes for the Portland Harbor Superfund Site where there are over 150 PRPs. Response costs, including remediation and natural resource damage assessments and injuries will ultimately be paid as non-reimbursable expenses from the United States Judgment Fund, not the Bonneville Fund. For the other facility, investigations are still in early stages; even if Bonneville were determined to be liable, the cost associated with cleanup of this site is expected to be less than $3 million.

As a separate and distinct matter, the Corps has its own CERCLA liability and is exercising its Executive Order 12580 cleanup implementation authority at two Corps-operated facilities (Big Cliff Reservoir Former Construction Site/Detroit Project and Bradford Island) at Federal System Hydroelectric Projects (Detroit Project, including Detroit and Big Cliff Dams and Reservoirs and Bonneville Project). The EPA listed Bradford Island as a Superfund site in March 2022. Bonneville does not have CERCLA liability at either site and is not potentially responsible for contamination; however, the Corps has applied the power generation share of the joint operation and maintenance expense funds received from Bonneville for the Detroit and Bonneville Projects to the Corps' early stage cleanup at these two sites. Employing its direct funding mechanism through Fiscal Year 2025, such costs were approximately $2.1 million in Fiscal Years 2023-2024 and Bonneville expects less than $1 million in costs in Fiscal Year 2025. Starting in Fiscal Year 2026, Bonneville decided to reimburse the U.S. Treasury for the Corps' appropriately assigned environmental liability costs rather than employ its direct funding mechanism – the Corps has received $25 million in appropriations for Fiscal Years 2025-2030, so Bonneville's appropriately assigned joint O&M costs could be up to approximately $12.5 million for that time period. For additional details regarding Corps costs allocated to power generation at Federal System Hydroelectric Projects, see "POWER SERVICES—Description of the Generation Resources of the Federal System—Federal Hydro-Generation."

Energy Policy Act of 2005

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

(i) EPA-2005 amends the FPA to authorize FERC to require an unregulated transmitting utility (a term that includes Bonneville) to provide transmission services at rates comparable to those the utility charges itself, and on terms and conditions that are comparable to those the utility offers itself and that are not unduly discriminatory or preferential. See "—Renewable Generation Development and Integration into the Federal Transmission System" for discussion of special tariff provisions related to compensation of non-federal generators (primarily wind generators) for being displaced in oversupply events that were established after FERC exercised its authority under this provision in response to a complaint related to displacement as a result of oversupply events filed by certain customers against Bonneville.

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

(iii) EPA-2005 grants FERC limited authority to order refunds in the case of certain energy sales by non-jurisdictional utilities such as Bonneville. The refund authority is limited to sales of 31 days or less made through an organized market in which the rates for the sale are established by a FERC-approved tariff. The refund authority applies to Bonneville only if the rate for the sale by Bonneville is unjust and unreasonable and is higher than the highest just and reasonable rate charged by any other entity for a sale in the same geographic market for the same or most nearly comparable time period.

(iv) EPA-2005 authorizes FERC to certify and oversee an Electric Reliability Organization ("ERO") that will be authorized to issue mandatory reliability standards that cover all users, owners, and operators of the bulk power system. WECC acts for the North American Electric Reliability Corporation ("NERC"), which is the ERO established by FERC. The mandatory reliability standards apply to Bonneville, but EPA-2005 expressly states that neither the ERO nor FERC is authorized to order the construction of additional generation or transmission capacity or to set and enforce compliance with standards for adequacy or safety of electric facilities or services. Monetary penalties for violation of the standards may be assessed by the ERO and approved by FERC, or assessed by FERC itself. However, neither the ERO nor FERC has jurisdiction to assess a monetary penalty against the United States, including Bonneville. Thus, while Bonneville must still comply with the mandatory reliability standards, it does not face penalties, monetary or otherwise, for any violations.

Other Applicable Laws

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

Columbia River Treaty

Bonneville and the Corps have been designated by executive order to act as the "United States Entity," which, in conjunction with a Canadian counterpart, the "Canadian Entity," formulates and carries out operating arrangements necessary to implement the 1964 Columbia River Treaty (the "Treaty"). The United States and Canada entered into the Treaty to increase reservoir capacity in the Canadian reaches of the Columbia River basin for the purposes of power generation and flood control. Pursuant to the Treaty, Canada constructed the Mica, Arrow and Duncan hydroelectric projects in Canada to provide 15.5 MAF of storage that allows for regulation of streamflow, which in turn increases power production and provides flood risk management for both the United States and Canada.

For power production, regulation of streamflow by the Canadian reservoirs enables certain hydroelectric projects, some of which are part of the Federal System, that are located in the United States on or near the Columbia River to produce more usable energy than otherwise would occur in the absence of Canadian storage. This increase in usable energy is termed 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 point along the United States-Canada border near Oliver, British Columbia unless the United States Entity and the Canadian Entity agree to other arrangements. In the late 1990s, the United States Entity and Canadian Entity reached such an agreement through 2024, 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 during the term of the agreement.

The United States Entity and Canadian Entity have previously 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 through 2024 by the executive branches of the United States and Canadian governments through an exchange of diplomatic notes, which occurred in 1999.

Under the Treaty, Canadian storage operates to meet planned Regional firm loads during low water conditions providing additional water downstream for hydro-generation to help meet the loads of Bonneville and certain other Regional utilities. This Treaty operation is incorporated into Bonneville's estimate of the firm power of the Federal System under Low Water Flows/Firm Water. See "POWER SERVICES—Description of the Generation Resources of the Federal System."

For flood risk management, the storage in Canada is generally drafted through the fall and winter to create storage space and refilled during the spring/summer runoff to manage floods. The Treaty provides for assured flood risk management operations in Canadian reservoirs until September 2024 to reduce flood impacts to communities in both Canada and the United States. The Treaty called for a change in the procedures for flood risk management operations in September 2024, and the Entities and their governments will be discussing how to coordinate and implement this change.

The Treaty has no expiration date and thus could continue indefinitely. The Treaty does, however, allow either the United States or Canada to elect to terminate the Treaty (except for primarily its flood risk management provisions) at any time after September 2024, but only if at least ten years' written notice has been provided. No such notice has been issued by either country.

On December 13, 2013, the United States Entity sent a final Regional Recommendation concerning the post-2024 future of the Treaty to the United States Department of State. In general, the Regional Recommendation proposed to modernize the Treaty to more fairly reflect the distribution of operational benefits between the United States and Canada; to ensure that flood risk management, an economical and reliable power supply, and other key river uses are preserved; and to address key ecosystem functions in a way that complements the significant investments made to protect fish and wildlife over the past three decades. The final recommendation submits that the Pacific Northwest Region and the United States would benefit from modernization of the Treaty post-2024.

In 2015, the United States government concluded a federal interagency review on the question of the post-2024 future of the Treaty. This review was conducted under the general direction of the National Security Council on behalf of the President of the United States and was coordinated and overseen by the United States Department of State. The United States Department of State then named a lead negotiator and began working with the United States Entity and other federal agencies toward completing the official authorization which would allow the United States government to negotiate with Canada. In late 2016, the United States Department of State approved this negotiation authorization. The United States and Canada began negotiations to modernize the Columbia River Treaty regime in May 2018.

In July 2024, the United States and Canada reached a non-binding agreement on core issues to be reflected in a modernized Treaty, and the Countries have begun to negotiate and draft modernized Treaty text. During the pendency of these negotiations, the Countries agreed to implement a set of interim measures concerning the following aspects of Columbia River coordination:

- Beginning August 1, 2024, the Canadian Entitlement was reduced from 1141 Megawatts (MW) of hydropower generation capacity and 454 average MW (aMW) of energy to 660 MW of capacity and 305 aMW of energy. Over the next 20 years, the Canadian Entitlement will further decrease and stabilize in the 2033-2034 operating year at 550 MW of capacity and 225 aMW of energy.
- Effective November 1, 2024, Powerex Corp. assumed and started paying for 1,120 megawatts of transmission rights previously held by Bonneville to deliver the Canadian Entitlement.
- From September 2024 through 2027, Canada will provide 3.6-million-acre feet of water storage at Arrow Lakes reservoir for flood risk management for the United States, upon election and compensation by the Corps on behalf of the United States.
- Canada will provide up to 1.0 million acre feet of flow augmentation to aid in salmon migration in the 2024-2025 operating year.

The negotiations of modernized Treaty text are currently paused while the new administration conducts a policy review. During this period, Bonneville along with the Corps is continuing to carry out and implement operational and other obligations pursuant to the current Treaty and associated agreements.

Proposals for 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 all or part of the federal power marketing agencies, including Bonneville, privatizing new and replacement capital facilities at federal hydroelectric projects, studying the breaching or 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 Non-Federal Debt. For a discussion of certain actions related to the change in administration that affect Bonneville, see "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Change in Administration."

Previous administrations have, from time to time, included in their President's Budget Requests to Congress, proposals to sell assets owned and operated by the PMAs, including those of the Southwestern Power Administration, Western Area Power Administration, and Bonneville and to authorize the PMAs to charge rates comparable to those charged by for-profit, investor-owned utilities, rather than being limited to cost-based rates, for electricity. Bonneville is unable to predict whether similar proposals or any other proposal with respect to Bonneville will be included in future President's Budget Requests to Congress or the effects any such proposal would have on Bonneville or its Non-Federal Debt if enacted into law.

Federal Debt Ceiling

In order to fund its general operations, the United States relies on current receipts and the proceeds of debt obligations issued by the United States Treasury. In recent years, the United States has narrowly avoided a situation where it would be unable to fund all of its operations because it reached the Congressionally-established debt ceiling. A future failure to raise the United States Treasury debt ceiling could result in default by the United States and have adverse implications on all funds held by the United States Treasury, including the Bonneville Fund. It is possible that actions taken or not taken by the United States Treasury or others at such times could materially affect Bonneville's operations and financial condition, including, among other things, restricting Bonneville's ability to borrow either short- or long-term from the United States Treasury and Bonneville's access to the Bonneville Fund to meet its cash payment obligations, including under the Net Billing Agreements, the 1989 Letter Agreement, and the Direct Pay Agreements. On June 3, 2023, President Biden signed legislation suspending the debt ceiling until January 1, 2025, and a new debt limit was established on January 2, 2025. The United States Treasury began implementing "extraordinary measures" on January 21, 2025, to allow for continuation of normal operations without defaulting on the United States' debt. It is unknown when the extraordinary measure will run out, but most forecasts point to late spring/early summer of 2025.

Government Shutdown and Effects on Bonneville

From time to time, most recently during Fiscal Year 2019, Congress has failed to timely enact federal appropriations legislation which has resulted in the shutdown of many of the Federal government's operations. Bonneville's funding and the operation of the Federal System are not affected by the lack of enactment of federal budget legislation.

Direction or Guidance from other Federal Agencies

Bonneville is part of the federal government. It is subject to direction or guidance in a number of respects from the OMB, 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.

Preparedness, Cyber, and Physical Security

Areas of increased attention in the electric power industry include managing risks to assure operational continuity and assurance of both cyber security and security of physical assets. 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 and testing of plans, systems and facilities to continue to operate through, or quickly recover from, a major disruption. Bonneville operates redundant system control centers that are geographically separated, one east and one west of the Cascade Mountains, in areas not subject to the same geographic vulnerabilities. In a major disruptive event, either control center will be capable of managing transmission capacity and power sales as well as coordinating power generation operations.

New technical cyber vulnerabilities are discovered in the United States daily. In addition, cyber-attacks have become more sophisticated and increasingly are capable of impacting industrial control systems and components. To face these and other challenges of cyber security, Bonneville is taking several key steps to expand its cyber security capabilities. Bonneville is working on implementation of a program known as Continuous Diagnostics and Mitigation which provides real-time detailed centralized cyber security monitoring of inventory, hardware, software and data as well as vulnerabilities that can be addressed. This is part of a government-wide effort sponsored by the United States Department of Homeland Security's Cybersecurity and Infrastructure Security Agency. Bonneville has permanent, full-time staff in its Office of Cyber Security to perform offensive cyber security research and penetration testing, to gather and analyze intelligence threat information to stay abreast of new vulnerabilities, and to assess exposure and respond accordingly to mitigate threats and share information. Bonneville has also developed alliances within the federal government to deploy intelligent devices to monitor external threats from the Internet and implemented a Cyber Security Operations and Analysis Center to improve Bonneville's capability and situational awareness. Bonneville participates in the joint government-Electric Subsector Coordinating Council as well as other industry groups with a focus on anticipating and mitigating cyber security risks and is subject to the mandatory NERC reliability standards including cyber security standards.

Bonneville continues to enhance its operational security through the implementation and monitoring of a prioritization of real time cyber security controls in pursuit of anomalous activity and offensive cyber security research on operational technology. Bonneville believes that these efforts will help it face the challenge of increasing use of digital devices and increasing threats.

Bonneville's Physical Security Office is responsible for enacting and managing a comprehensive physical security program that is risk based and in compliance with multiple regulations, including DOE orders and applicable North American Electric Reliability Corporation Critical Infrastructure Protection ("NERC-CIP") standards, and United States Department of Homeland Security requirements. The physical security approach by Bonneville strives to meld these various requirements into one sustainable program. This program seeks to incorporate industry best practices where possible and also collaborate with other utilities, power marketing administrations, and industry partners.

The physical protection strategy employed by Bonneville attempts to gain security capabilities to deter, detect, delay, assess, communicate and respond to security-related threats and events. As Bonneville works to physically protect its buildings and facilities, Bonneville categorizes assets based on mission criticality and then applies security measures which include: physical hardening, contract security officers, physical access control systems, intrusion detection systems, and video assessment and surveillance systems based on the critical nature of the asset.

Another program element adopted by Bonneville includes an ongoing Threat Awareness and Threat Management program. Bonneville's Physical Security Office dedicates personnel resources to monitor threat intelligence information, maintain relationships and partnerships with state Fusion Centers, DOE Counter-Intelligence, the Electric Sector Information Sharing and Analysis Center, as well as federal, state and local law enforcement agencies. This internal capability helps Bonneville to remain aware of and adapt to the evolving threat picture.

Physical security policy and program effectiveness are assessed through Bonneville's Security Performance and Assurance Program, security risk assessment processes, Bonneville's annual NERC-CIP certification process, DOE self-assessment reporting for Safeguards and Security topical areas, and Bonneville's Office of Security and Continuity of Operations annual internal self-assessment activities for Safeguards and Security programs. Through these established efforts, the Office of Security and Continuity of Operations is able to monitor Safeguards and Security effectiveness, efficiency, and compliance with DOE and NERC-CIP security related requirements. Additionally, the Office of Security and Continuity of Operations is able to assess the performance of the layers of security and related programmatic areas.

Both Bonneville's cyber and physical security programs are subject to regular audits by the DOE Inspector General to evaluate compliance with DOE and federal standards.

Renewable Generation Development and Integration into the Federal Transmission System

In the past few decades, Bonneville has integrated a significant number of generation projects into its balancing authority area in the Region, and is responsible for transmitting electric power into or through the Region. Integrating new resources has required and may continue to require transmission facility investments, such as new transmission lines and substations or improvements to existing facilities, in order to transmit the additional electric power. Much of the power generation development in the Region has been from wind projects. Bonneville estimates that 5,898 megawatts of wind generation facilities are now interconnected to the Federal Transmission System and approximately 2,829 megawatts are currently in Bonneville's balancing authority area. By the end of Fiscal Year 2026, Bonneville expects that it will integrate into the Federal Transmission System an additional 1,596 megawatts of wind generation facilities (bringing the total wind integrated into the Federal Transmission System to 6,494 megawatts).

From a power marketing perspective, the development of large amounts of wind generation in the Pacific Northwest has also affected power market prices and the revenue Bonneville obtains for its surplus power sales, in particular the sale of seasonal surplus energy. It has also resulted in Power Services providing significant generation capacity and energy needed to provide ancillary services needed for wind energy integration, namely generation imbalance services. Wind energy is intermittent and variable, and does not always generate energy as expected. To ensure the expected energy is available, other generating resources must stand ready to increase and decrease generation in short order to ensure expected energy amounts are delivered to load.

Integrating renewable resources, particularly wind resources, can pose other operational challenges for the Federal System. For instance, in spring and summer months, high river flows can lead to situations in which turbines at certain Federal System dams must generate electric power to protect fish populations from the harmful effects of excessive gas levels in the river. Running water though the dams' turbines rather than over the dams' spillways reduces gas formation but it unavoidably generates electric power that must be used (taken to load). This can create an oversupply of generation, which, if uncorrected would lead to power system instability. Oversupply can be resolved operationally by the substitution ("displacement") of non-federal generation (including wind generation) with Federal System hydropower.

A central feature of Bonneville's management of oversupply to protect fish is to displace wind generation at times when (i) aggregate electric generation exceeds electric system demand, (ii) increased hydroelectric generation is necessary to keep dissolved gas concentrations within acceptable limits, and (iii) displacement of non-federal generation with low-cost or free Federal System hydroelectric power is inadequate to mitigate excess gas levels. Bonneville has also established special tariff provisions, which have been approved by FERC, to compensate non-federal generators (primarily wind generators) for being displaced in oversupply events when free or low-cost Federal power displacement is inadequate to induce sufficient displacement. Bonneville recovers the costs of oversupply compensation in its rates in accordance with transmission rate provisions that have also been approved by FERC.

Almost all of the new renewable generation in the Region in the last ten years has been in the form of wind generation; however, Bonneville has seen an increase in solar power development. As with wind generation, solar power is highly variable and presents transmission system integration challenges. Solar output is easier to predict over the course of a day and is less challenging to integrate than wind generation; however, the second-to-second variability due to clouds crossing the solar site requires that Bonneville keep more spinning reserves online. Bonneville estimates that 696 megawatts of utility scale solar generation facilities are now interconnected to the Federal Transmission System and approximately 222 megawatts are currently in Bonneville's balancing authority area. By the end of Fiscal Year 2026, Bonneville expects that it will integrate into the Federal Transmission System an additional 427 megawatts of solar resources (bringing the total solar integrated into the Federal Transmission System to 1,123 megawatts).

Regional Market Initiatives

Day Ahead Markets in the West

Since 2018 through its grid modernization initiative, Bonneville has invested in modernizing its systems and processes to enhance transmission and generation operations. Such investments enabled Bonneville to make its first step into organized markets in Fiscal Year 2022 when it joined the Western Energy Imbalance Market and positions Bonneville to be prepared for other potential market development options.

Bonneville has been exploring the potential for organized energy market options to enhance the efficient delivery of reliable and affordable hydropower to its customers. Bonneville has been evaluating the two day-ahead and real-time market offerings that have emerged in the West: (i) Cal-ISO's Extended Day Ahead Market ("EDAM") and (ii)

Southwest Power Pool's Markets+ ("Markets+"), both of which have FERC-approved tariffs. Bonneville has been heavily engaged in the development of each markets' design and governance, recognizing that independent governance is an essential aspect of any potential future market to ensure neutrality in market development, implementation and operation.

In July 2023, Bonneville began to engage the region in a public process to evaluate its potential participation in a day-ahead energy market.

After thorough evaluation of the EDAM and Markets+ market options including governance, operational and commercial impacts, and other factors, Bonneville released a Draft Policy to join Markets+ in March 2025.

To support the development of Markets+, in February 2023, Bonneville announced a commitment of resources for Phase 1 development of Markets+. Bonneville's share of the total Phase 1 costs to date are approximately $1.5 million. Phase 1 funded activities through filing of the Markets+ tariff, which occurred in March 2024 and was approved by FERC in January 2025. Since the tariff was filed in March 2024, Bonneville's continued costs have been approximately $75,000 per month.

In February 2025, Bonneville committed to fund Phase 2 of Markets+, which will include remaining development through the market go-live. Based on the current parties supporting Phase 2 (which will involve a two-stage process), Bonneville's total commitment for Phase 2 will not exceed $40.19 million in development costs incurred by Southwest Power Pool. Bonneville's Phase 2, Stage 1 commitment is $26.8 million. Bonneville's commitment for Phase 2, Stage 2 could be up to $13.39 million. If Bonneville joins Markets+, development costs will be recovered pursuant to a rate applied to each market transaction likely over the first five to ten years of market operations. If the Markets+ effort does not continue, Bonneville will be liable for its proportionate share of development costs incurred up to the time of termination. Bonneville expects additional parties to join the Phase 2 effort, which would reduce its overall liability. If Bonneville joins Markets+, Bonneville estimates that implementation costs would be between $53 million to $74 million (primarily related to software and labor) and on-going market participation fees are expected to be $15 million per year.

Bonneville continues to monitor the development of EDAM, including the West-wide Pathways Governance Initiative to study and propose a path for regionalization of the California-based market. In February 2022, a bill was introduced in the California legislature to allow California entities to participate in a newly established Regional Organization. Bonneville continues to monitor and engage with EDAM governance initiatives, as well as ongoing EDAM stakeholder processes related to market design.

Bonneville expects to release its final policy decision and record of decision in May 2025. Bonneville's decision will be dependent on implementation in rate and tariff proceedings.

Western Resource Adequacy Program

Beginning in 2019, entities in the West have come together through an initiative facilitated by the Western Power Pool ("WPP") to scope and develop a resource adequacy program. The Western Power Pool's Western Resource Adequacy Program ("WRAP") is the product of a proactive effort by the region to address resource adequacy concerns driven by changing factors in the energy industry due to decarbonization in multiple sectors (e.g., energy, housing and transportation) and climate change. Traditional carbon-intensive resources are being replaced with cleaner renewable resources that have different generation attributes, profiles and impacts on the interconnected energy grid than their predecessors. The WRAP uses common planning metrics to increase transparency into resources and transmission needed to reliably supply power to meet existing and future load demands in the WRAP's footprint. As more intermittent generators are integrated into the grid and more extreme weather events occur, resource adequacy will be crucial for maintaining grid reliability in the West. The WRAP provides another tool to help ensure there is enough capacity to meet the area's power needs through coordination, established metrics and transparency among participants. In addition to increased grid reliability, the WRAP enables planning across a larger footprint using a diverse array of resources that could enable greater efficiencies and potentially reduce costs for the region's utilities and ratepayers.

The tariff that implements the WRAP was filed with the FERC on August 31, 2022. FERC approved the tariff on February 10, 2023, which enabled WRAP to set terms and conditions for participation and allow for governance changes to be made. On December 16, 2022, following the completion of a public process, Bonneville made a decision, contingent on tariff approval referred to above, to join the binding phase of the WRAP. The binding phase is expected to commence for the Winter 2027-2028 season when all participants will be required to meet all operational and compliance obligations of the program.

All business practices have been approved by subcommittees and the independent WPP Board of Directors. Bonneville and other participants are submitting data for the non-binding forward showing evaluations and curing any deficiencies identified by WPP in preparation for the binding phase of the program.

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 by the DOE and subsequently by the United States Office of Management and Budget. The Office of Management and Budget 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 Federal System Hydroelectric 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 or through Bonneville's Non-Federal Debt Programs.

Bonneville is required by statute to establish rates that are sufficient to repay its Federal Appropriations Repayment Obligations 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, 2024, Bonneville had repaid $19 billion of principal of the Federal System investment and had approximately $1.7 billion principal amount outstanding with regard to such appropriated investments and $6.0 billion principal amount outstanding in bonds issued by Bonneville to the United States Treasury. Congress has continued to, and is expected to continue to, appropriate amounts for certain fish and wildlife investments in the Federal System. See the discussion of the Columbia River Fish Mitigation in "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Fish and Wildlife—The Endangered Species Act."

Bonneville's repayment obligations include the payment of "irrigation assistance," which relates to appropriations provided to Reclamation to construct irrigation facilities associated with its Federal System projects. Bonneville's irrigation assistance obligation is limited to an amount of appropriations that is deemed under Reclamation policy to be beyond the ability of irrigators to pay. Examples of appropriated irrigation investments include water pumps, reservoir facilities and canals within the authorizations for the Federal System Hydroelectric Projects owned by Reclamation. These repayment obligations do not incur interest. 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, payments for irrigation assistance 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 $2 million and $21 million per year over the next ten years.

Internal Guidance Affecting Bonneville Financial Operations

In August 2023, Bonneville published its updated five-year strategic plan for calendar years 2024 through 2028 (the "2024-2028 Strategic Plan") that identified the prioritized set of actions Bonneville expects to take to improve Bonneville's commercial performance and position it to adapt to a rapidly transforming energy industry. The 2024-2028 Strategic Plan sets forth the following six strategic goals that Bonneville expects will be its central reference point over the next five years: (i) sustain financial strength; (ii) modernize business systems and processes; (iii) enhance the value of products and services; (iv) preserve safe and reliable system operations; (v) invest in people and (vi) mature asset management. The supporting Financial Plan, initially published on September 30, 2022, outlined three financial health objectives that guide Bonneville's focus on financial health: (i) cost management discipline, (ii) financial resiliency, and (iii) independent financial health assessment. These objectives are designed to support Bonneville's ability to deliver on its mission and meet its multiple statutory obligations under various conditions. Bonneville continues to focus on its financial health objectives and has set a specific long-term debt-to-asset ratio target.

Bonneville previously employed a Leverage Policy that guided Bonneville's debt management practices. The Leverage Policy required that each business line maintain or decrease its debt-to-asset ratio over time and set a target debt-to-asset ratio of 75-85 percent by Fiscal Year 2028 and a long-term target debt-to-asset ratio of 60-70 percent beyond Fiscal Year 2028. As part of its efforts to publish the 2022 Financial Plan, Bonneville adopted a Sustainable Capital Financing Policy that establishes guidelines around how Bonneville will obtain funds for its capital investment program and also provides an updated debt-to-asset ratio target. The Sustainable Capital Financing Policy supersedes the Leverage Policy and provides a long-term target debt-to-asset ratio of 60 percent by Fiscal Year 2040. At a minimum, each business line will fund ten percent of its capital program with revenue financing. The remainder is to be funded with bonds issued to the United States Treasury or by other means. When establishing rate case assumptions for development of rates for each rate period, if a business line is not on a path to achieve a 60 percent debt-to-asset ratio by 2040, it will incrementally increase the amount of revenue financing to fund 20 percent of its capital program; however, the amount of revenue financing is capped to ensure that the total amount of revenue financing for a business line will not result in more than a one percent rate increase.

Since release of the plans, Bonneville has made progress towards each of its financial objectives. At the end of Fiscal Year 2024, Bonneville's Days Cash on Hand was 116 days, significantly exceeding the minimum threshold outlined in the Financial Plan. At the end of the Fiscal Year 2024, the agency debt-to-asset ratio was 80 percent. In the Final 2024-2025 Rates, both power and transmission rates include a planned amount of revenue financing in each of the two fiscal years of the rate period (which averaged $34 million per year for power and averaged $55 million per year for transmission), which is contributing to improvement of the overall debt-to-asset ratio. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Current Bonneville Power and Transmission Rates."

Bonneville's Treasury Borrowing Authority

Bonneville is currently authorized to issue and sell to the United States Treasury, and to have outstanding at any one time, up to $13.7 billion aggregate principal amount of bonds. Beginning in Fiscal Year 2028, an additional $4 billion will become available as provided for in the Infrastructure Investment and Jobs Act legislation that authorized the $10 billion increase. Of the $13.7 billion in borrowing authority that Bonneville has with the United States Treasury, bonds in the principal amount of $6.0 billion were outstanding as of the end of Fiscal Year 2024. To reduce overall interest expense, Bonneville may delay borrowing from the United States Treasury until necessary from a cash flow perspective which increases the Deferred Borrowing (as hereinafter defined) balance. For more details related to Deferred Borrowing, see "BONNEVILLE FINANCIAL OPERATIONS—Bonneville's Use of Non-GAAP Financial Metrics." If the full amount of Deferred Borrowing reported as part of Bonneville's Total Financial Reserves had been borrowed at the end of Fiscal Year 2024, the total amount of bonds outstanding as of the end of Fiscal Year 2024 would have been $6.5 billion. 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 currently available $13.7 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 $12.45 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 2024, the interest rates on the outstanding bonds ranged from 0.4 percent to 5.9 percent with a weighted average interest rate of approximately 3.4 percent. The original terms of the outstanding bonds vary from one to 30 years. As of the end of Fiscal Year 2024, Bonneville's outstanding bonds issued to the United States Treasury included $392 million in variable rate bonds at an average interest rate of 4.80 percent at such time. The term of the bonds is limited by the average expected service life or the maximum repayment period, whichever is shorter, of the associated investment: 35 years for transmission facilities, 50 years for Corps and Reclamation capital investments, up to 20 years for conservation investments, and 15 years for fish and wildlife projects. Bonds are 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 for short-term operating expenses. Under the short-term operating expense borrowing arrangement, Bonneville may borrow and have outstanding at any one time up to $750 million in aggregate. The short-term operating expense 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 aggregate principal amount of debt that Bonneville may issue to the United States Treasury and have outstanding at any one time. In recent years, Bonneville has made draws on the short-term operating expense note but has repaid such draws prior to the end of the fiscal year in which the draws were made.

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. Under the Investment MOU, Bonneville invests the applicable cash reserves in the Bonneville Fund in certain interest bearing securities ("market-based special securities") issued by the United States Treasury. In general, the market-based special securities bear interest by reference to the published yield curve for United States Treasury debt at the time of the investment.

The United States Treasury's ability to meet requests by Bonneville may be affected by a failure to raise the United States Treasury debt borrowing ceiling. See "MATTERS RELATING TO POWER SERVICES AND TRANSMISSION SERVICES—Federal Debt Ceiling."

Bonneville's Non-Federal Debt

To meet its capital program, Bonneville has relied on the Congressionally-enacted authority to borrow from the United States Treasury; however, Bonneville has also entered into various arrangements to meet its capital program which involve debt issued by third parties, the repayment of which is secured by Bonneville financial commitments. Bonneville has also employed electric power prepayments as a funding source. Bonneville refers to these commitments as "Non-Federal Debt." As of September 30, 2024, aggregate Non-Federal Debt outstanding was approximately $7.3 billion. By way of comparison, as of September 30, 2024, the principal amount of unrepaid appropriations for Federal System investments was approximately $1.7 billion, and the outstanding principal amount of bonds issued by Bonneville to the United States Treasury was $6 billion. Described below are the currently outstanding forms of Non-Federal Debt and a description of possible Non-Federal Debt transactions in the near future.

Net Billed Bonds

Net Billed Projects represent the largest single component of Non-Federal Debt: $5.2 billion out of a total of $7.3 billion aggregate Non-Federal Debt, as of September 30, 2024.

The amounts potentially subject to net billing are substantial. The debt service on the Net Billed Bonds in Fiscal Year 2024 was $402 million. In addition, the operations and maintenance expense for the Columbia Generating Station in Fiscal Year 2024 was $315 million. For more details related to the Columbia Generating Station, see the Official Statement under "ENERGY NORTHWEST—The Columbia Generating Station."

As discussed in the Official Statement under "ENERGY NORTHWEST—Energy Northwest Indebtedness," since 2001, Energy Northwest and Bonneville have worked together to refinance certain maturities of the Net Billed Bonds so that the weighted average maturities more closely match the originally expected useful lives of the related Net Billed Project facilities.

Bonneville manages its overall debt portfolio, which includes Non-Federal Debt and Bonneville's repayment obligations to the United States Treasury, to meet the objectives of: (i) minimizing the cost to Bonneville's ratepayers, (ii) maximizing Bonneville's access to its lowest cost capital sources to meet future capital needs, and (iii) maintaining sufficient financial flexibility to meet Bonneville's financial requirements.

Bonneville's Strategic and Financial Plans, initially published in 2018, identified continued access to low-cost capital and preservation of Bonneville's United States Treasury borrowing authority capacity as key to Bonneville's long-term financial health. In September 2018, the Energy Northwest Executive Board adopted a motion supporting the extension of the Regional Cooperation Debt initiative through Fiscal Year 2030; the issuance of additional Net Billed Bonds will require approval of the Energy Northwest Executive Board.

The current phase of Regional Cooperation Debt refinancings has and will have the effect of freeing up amounts in the Bonneville Fund which otherwise would have been used to fund the repayment of the principal of the refunded Net Billed Bonds. In addition, this phase of Regional Cooperation Debt also includes the issuance of Net Billed Bonds to fund a portion of the interest coupon payments allocable to unamortized bond premiums related to certain outstanding Net Billed Bonds. The freed up funds resulting from the refinancings or issuance of Net Billed Bonds for interest coupon payments would enable Bonneville (i) to make payments to reduce the outstanding principal amount of bonds issued by Bonneville to the United States Treasury to help restore or preserve Bonneville's available capacity of its United States Treasury borrowing authority or (ii) to directly fund Bonneville capital investments.

Bonneville expects that Energy Northwest will continue to issue Net Billed Bonds to fund new capital investments for the Columbia Generating Station which are expected to be made in the amount of approximately $3.6 billion from July 2024 through June 2035. See the Official Statement under "ENERGY NORTHWEST—The Columbia Generating Station—Capital Improvements." Additional Net Billed Bonds for additional capital investments for Columbia Generating Station may be issued thereafter. In addition, Bonneville expects to continue to work with Energy Northwest to issue up to an additional $2.4 billion of Net Billed Bonds through 2030 to: (i) refinance certain Net Billed Bond debt to extend the average maturity of the outstanding principal balance of such debt to match more closely the originally expected economic useful lives of the facilities financed thereby, or (ii) fund a portion of the interest coupon payments related to certain outstanding Net Billed Bonds. A portion of the Series 2025 Bonds will refinance Net Billed Bonds. In Fiscal Year 2024, Energy Northwest issued approximately $189 million of Net Billed Bonds under the Regional Cooperation Debt approach which enabled Bonneville to prepay approximately $215 million of outstanding Federal Debt over the amounts that Bonneville was scheduled to repay in Fiscal Year 2024. See the Official Statement under "ENERGY NORTHWEST—Energy Northwest Indebtedness."

Bonneville's Transmission Facility Lease-Purchase Program

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

Bonneville currently has two long-term lease-purchase arrangements with the Idaho Energy Resources Authority ("IERA"), one long-term lease-purchase arrangement with Northwest Infrastructure Financing Corporation, and eight long-term lease-purchase arrangements with the Port of Morrow, Oregon.

Bonneville expects that prior to September 2025 the IERA will issue up to $110 million of Bonneville-supported bonds (federally taxable) to refinance certain transmission facilities owned by the Port of Morrow, Oregon and funded through long-term bonds. The debt service of such bonds will be secured by Bonneville's rental payments under a long-term lease-purchase agreement. The IERA has taken no official action to authorize such additional bonds.

The aggregate principal amount of publicly-issued bonds associated with Bonneville's lease-purchase agreements was $1.8 billion as of September 30, 2024.

Electric Power Prepayments

In Fiscal Year 2013, Bonneville and four Preference Customers agreed to separate electricity prepayment arrangements in which the Preference Customers provided lump-sum payments to Bonneville as prepayments of a portion of their power purchases through September 30, 2028, the termination date of the Long-Term Preference Contracts. The participating customers are entitled to future deliveries of a portion of the electricity pursuant to such Long-Term Preference Contracts without additional payments. The right to future deliveries of that portion of electricity without additional payments is and will be reflected as fixed equal monthly credits to the participating customers' power bills from Bonneville. The prepayments are not for fixed blocks of electricity. The prepayments entitle the participating customers to receive a fixed monthly value of electricity, valued at Bonneville's then-applicable power rates. Bonneville received $340 million in aggregate of prepayments from the participating customers, all of which has been expended on Federal System hydroelectric facility investments. 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.

As of September 30, 2024, outstanding Non-Federal Debt associated with electric power prepayments was $112 million.

While Bonneville has no current plans to do so, it is possible that Bonneville may seek to use electric power prepayments to meet some of its future capital funding needs.

Resource Acquisitions

Under this form of Non-Federal Debt, Bonneville enters into resource acquisition agreements in which a third party issues bonds, the proceeds of which are used to construct or acquire generating facilities or to fund energy conservation measures, the project capability or conservation savings of which are provided to Bonneville. As of September 30, 2023, outstanding Non-Federal Debt for generating resource acquisitions was $49 million. 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." While Bonneville has no current plans to do so, it may seek to use this form of Non-Federal Debt to acquire electric power generating and conservation resources to meet some of its future capital funding needs.

Total Non-Federal and Federal Debt

The following table depicts the types and amounts of Non-Federal and Federal Debt outstanding as of the end of each of Fiscal Years 2022 through 2024. Any discrepancies in totals for figures portrayed in this table are due to rounding.

Non-Federal and Federal Debt, Fiscal Years 2022-2024
(Dollars in millions)

Non-Federal and Federal Debt Outstanding

Projects Financed with Non-Federal Debt	**2024**	**2023**	**2022**
Non-Federal Generation			
Columbia Generating Station	$3,434	$3,382	$3,296
Cowlitz Falls Project	47	52	56
Terminated Generation			
Nuclear Project No. 1	829	837	824
Nuclear Project No. 3	967	971	950
Northern Wasco Hydro Project	2	4	5
Lease-Purchase Program	1,791	1,886	1,957
Finance Lease/Other Financial Liability	119	120	118
Customer prepaid power purchases	112	139	163
Total Non-Federal Debt	$7,301	$7,391	$7,369
Federal Debt			
Borrowings from U.S. Treasury	5,961	5,784	5,679
Federal appropriations	1,111	1,124	1,243
Federal appropriations (not yet scheduled for repayment)	586	474	398
Total Federal Debt	$7,658	$7,382	$7,320
Total Debt	**$14,959**	**$14,773**	**$14,689**

To the extent that Bonneville has entered into (or will enter into) arrangements involving Non-Federal Debt secured by cash payments by Bonneville, such as transmission facility lease-purchase arrangements and electric power conservation or generating resource acquisitions, the related debt service costs are and will be payable on the same parity as the Net Billed Project costs (including debt service on the Series 2025-A/B Bonds and other Net Billed Bonds) in the order in which Bonneville's costs are met. See "—Order in Which Bonneville's Costs Are Met." To the extent that Bonneville uses Non-Federal Debt that involves the provision by Bonneville of financial credits or offsets (including net billing credits with respect to the Net Billed Projects), such obligations may reduce the amount of cash otherwise available in the Bonneville Fund to meet Bonneville's cash payment obligations, including to meet debt service on the Series 2025-A/B Bonds and other Net Billed Bonds).

Bonneville's Capital Program

Bonneville operates in a capital intensive industry and expenditure levels for its capital program have been substantial. As with all capital investments, there is potential that certain investments may not be constructed to completion, provide the results expected, or achieve functionality for their full expected useful lives. The following table depicts Bonneville's capital investment levels by asset category for Fiscal Years 2020-2024. The following table excludes appropriated capital funding received by the Corps and Reclamation and capital investments associated with the Columbia Generating Station.

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

	2020	2021	2022	2023	2024	Total
Transmission(3)	$371	$413	$497	$650	$908	**$2,839**
Federal System Hydro	178	203	192	208	264	**1,045**
Fish and Wildlife	40	41	16	15	28	**140**
Facilities, Information Technology, Security(3)	20	23	16	13	18	**90**
Total	**$609**	**$680**	**$721**	**$886**	**$1,218**	**$4,114**

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

(2) PricewaterhouseCoopers LLP, Bonneville's independent auditor, has not audited, reviewed, compiled, or applied agreed-upon procedures with respect to the financial data in this table. Accordingly, PricewaterhouseCoopers LLP does not express an opinion or any other form of assurance with respect to the financial data.

(3) Certain amounts for Facilities, Information Technology, and Security related to Transmission Services are reported under Transmission.

To date Bonneville has met its capital program needs through various sources that include borrowing from the United States Treasury, and transactions involving Non-Federal Debt, as described above. Bonneville also uses funds from reserves and funds from customers in connection with "Projects Funded in Advance." Projects Funded in Advance are specific transmission capital investments that are made by Bonneville in the Federal Transmission System at the request of a customer or to meet a customer's transmission needs. The customer provides funds to Bonneville to construct all or a portion of the related facilities and in some circumstances certain customers may receive offsetting payment credits in future transmission bills from Bonneville. Bonneville owns the facilities in its own name. See "TRANSMISSION SERVICES—Bonneville's Federal Transmission System." The following table presents Bonneville's capital funding sources for Fiscal Year 2020 through Fiscal Year 2024. It excludes capital investments for the Columbia Generating Station and for the Columbia River Fish Mitigation as appropriated by Congress to the Corps.

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Historical Capital Funding by Source and Fiscal Year(1)
(Unaudited)(2)
(Dollars in millions)

	2020	2021	2022	2023	2024	Total
Borrowing from United States Treasury	$520	$617	$606	$822	$942	**$3,507**
Lease-Purchases(3)	38	22	-	-	-	**60**
Projects Funded in Advance	25	15	35	24	85	**184**
Revenue Funding	26	26	80	40	89	**261**
Freed Up Amounts in Bonneville Fund from RCD Actions(4)	-	-	-	-	102	**102**
Total	**$609**	**$680**	**$721**	**$886**	**$1,218**	**$4,114**

(1) Reflects actual capital expenditures funded by the related source, not the amount of the debt (or related liability) by source.

(2) PricewaterhouseCoopers LLP, Bonneville's independent auditor, has not audited, reviewed, compiled, or applied agreed-upon procedures with respect to the financial data in this table. Accordingly, PricewaterhouseCoopers LLP does not express an opinion or any other form of assurance with respect to the financial data.

(3) See "—Bonneville's Non-Federal Debt—Bonneville's Transmission Facility Lease-Purchase Program."

(4) Freed Up Amounts in Bonneville Fund from RCD Actions relate to amounts available in the Bonneville Fund which otherwise would have been used to fund the repayment of principal of the Energy Northwest net billed debt. Such amounts have enabled Bonneville to direct fund Bonneville capital investments. See "—Bonneville's Non-Federal Debt—Net Billed Bonds."

Bonneville's Capital Investment Expectations and Capital Process

To meet a variety of needs, Bonneville is forecasting aggregate planned capital expenditures comparable to or larger than levels in the recent past. Bonneville expects to fund substantial investment: (i) in the Federal Transmission System to assure reliable and secure 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, and (iii) to meet fish and wildlife capital commitments under the Columbia Basin Fish Accords, the applicable Columbia River System biological opinions, and the 2008 Willamette biological opinion. Bonneville's capital expenditures also include information technology, cyber and physical security, certain heavy equipment and certain costs related to financing.

In 2016, Bonneville introduced its Asset Management Key Strategic Initiative ("KSI") designed to bring a focus to asset management. Central to the focus is the effort to more closely align Bonneville's asset management program with ISO 55000 Asset Management as outlined in the Institute of Asset Management principles and practices. The key components of that alignment are strategic asset management plans ("SAMPs") and asset plans ("Asset Plans"), first developed by Bonneville in 2018. The SAMPs are a strategic document produced bi-annually in support of Bonneville's rate setting process. Asset Plans are produced annually and describe implementation of the SAMPs for a particular fiscal year.

The SAMPs provide a strategic approach that aligns with the goals in the 2024-2028 Strategic Plan. See "—Bonneville's Capital Financing Strategy." The more detailed and near-term Asset Plans are generally developed from the SAMPs. Each plan is created by using methodologies, dependent upon their asset management maturity, which calculates the investment needs. This process seeks to balance the often competing goals of keeping Bonneville's power and transmission rates as low as possible consistent with sound business principles, making timely and needed investments in the Federal System, and assuring sustainable long-term financial health. Planned investments at the Columbia Generating Station and certain other investments that Bonneville believes are not within its direct control to determine are considered in long-term rate analysis but are not part of the asset management processes, such as the SAMPs and Asset Plans, nor subject to these capital investment strategies.

Most of Bonneville's capital investments involve renewals, upgrades and replacement of existing facilities and are incremental in character.

In connection with developing the 2026-2028 Initial Rate Proposal, Bonneville has assumed the capital spending levels shown in the table that follows, with the exception of Fiscal Year 2025 details that are sourced from Bonneville's Fiscal Year 2025 year-end forecast as of December 31, 2024. These spending levels reflect the preliminary outcome of Bonneville's capital prioritization process and includes $2 billion of the $5 billion effort referred to as the Evolving Grid Projects. For more details regarding the Evolving Grid Projects, See "TRANSMISSION SERVICES—Bonneville's Federal Transmission System."

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

	2025	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**Total**
Transmission Fed System	$875	$1,097	$1,249	$1,282	$1,037	$1,028	$1,062	$778	$804	$823	**$10,035**
Hydro	244	305	309	310	305	307	308	317	328	334	**3,067**
Fish and Wildlife	59	50	86	92	124	47	33	38	71	38	**638**
Facilities, Information Technology, Security	162	262	270	141	88	94	91	92	95	89	**1,384**
AFUDC[(1)]	66	49	56	54	49	48	49	44	45	46	**506**
Total	**$1,406**	**$1,763**	**$1,970**	**$1,879**	**$1,603**	**$1,524**	**$1,543**	**$1,269**	**$1,343**	**$1,330**	**$15,630**

(1) AFUDC is based on forecasts of spend rates, completion dates and interest rates. AFUDC will be applied to specific program projects as construction begins and will accumulate during the construction period in accordance with Bonneville's accounting policy as described in Appendix B-1 to the Official Statement (Note 1 to Financial Statements).

The Forecast Capital Spending table above does not include investments projected by Energy Northwest for the Columbia Generating Station. Energy Northwest has developed a long-term capital investment strategy for the Columbia Generating Station in view of a 20-year operating license extension, evolving and expected guidance from the Nuclear Regulatory Commission, and other factors. The strategy identified $3.6 billion in additional capital requirements from July 2024 through June 2035. Bonneville expects that new capital needs for Columbia Generating Station will be funded with Net Billed Bonds issued by Energy Northwest, the debt service of which will be covered by Bonneville under Net Billing Agreements. See "—Bonneville's Non-Federal Debt—Net Billed Bonds." The Forecast Capital Spending table above also does not include investments related to the Columbia River Fish Mitigation program as appropriated by Congress to the Corps. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Fish and Wildlife."

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

Bonneville's Capital Financing Strategy

Given the large amount of potential Federal System investment described above, and based on current and forecast capital spending levels, and the amount of available United States Treasury borrowing authority, Bonneville has worked and continues to work with its customers to develop a strategic approach to assure that current capital investment sources described in the table above, including Non-Federal Debt (see "—Bonneville's Non-Federal Debt—Net Billed Bonds"), and borrowing from the United States Treasury, and other means, are sufficient to meet Bonneville's capital program and liquidity needs. Bonneville believes that Non-Federal debt actions, combined with Bonneville's recently increased United States Treasury borrowing authority capacity and other actions under its

Financial Plan (see "—Internal Guidance Affecting Bonneville Financial Operations") will enable Bonneville to meet its capital and financial liquidity needs beyond Fiscal Year 2044.

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 Pay 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 charged by Bonneville for such purchases.

Direct Funding of Federal System Operations and Maintenance Expense

In 1992, Congress enacted legislation authorizing but not requiring the Corps and the Department of Interior, encompassing both Reclamation and the Fish and Wildlife Service, to enter into direct funding agreements with Bonneville for operations and maintenance activities for the benefit of the Federal System. Under direct funding, periodically during the course of each fiscal year, Bonneville pays amounts directly to the Corps or the Department of Interior for operations and maintenance of their respective Federal System hydroelectric facilities as the Corps or the Department of Interior and Bonneville may agree. Bonneville now "direct funds" virtually all of the Corps and Reclamation Federal System operations and maintenance activities. Bonneville's cash payments for operations and maintenance expense to the Corps, Reclamation, and the Fish and Wildlife Service were \$276 million, \$180 million, and \$37 million, respectively, in Fiscal Year 2024.

Bonneville believes that the direct funding approach has increased Bonneville's influence on the Corps' and the Department of Interior's Federal System operations and maintenance activities, expenses, and budgets because, in general, Bonneville's approval is necessary for the Corps and the Department of Interior to assure funding. Under the direct funding agreements, direct payments from Bonneville for operations and maintenance are subject to the prior application of amounts in the Bonneville Fund to the payment of Bonneville's non-federal obligations, including Bonneville's payments, if any, with respect to the Net Billed Projects. Notwithstanding the foregoing, as a practical matter, since direct funding would be made by cash disbursement from the Bonneville Fund during the course of the year rather than as a repayment of a loan at the end of the year, it is possible that direct funding could be made to the exclusion of non-federal payments that would otherwise have been paid under historical practice. One result of direct funding obligations by Bonneville is that there has been and will be a reduction in the amount of Federal System operations and maintenance appropriations that Bonneville would otherwise have to repay, thereby reducing the amount of Bonneville's repayments to the United States Treasury that would otherwise be subject to deferral. Nonetheless, Bonneville expects to have approximately \$633 million to \$883 million in scheduled payments and planned discretionary payments each year to the United States Treasury, exclusive of the Corps' and the Department of Interior's operations and maintenance expenses, through Fiscal Year 2028. Bonneville has renewed and extended the direct funding operations and maintenance agreement with the Corps through Fiscal Year 2033. The direct funding operations and maintenance agreement with the Department of Interior is indefinite and does not require periodic renewals.

Order in Which Bonneville's Costs Are Met

Bonneville is required to establish rates sufficient to make, and Bonneville makes, certain annual payments to the United States Treasury. These payments are subject to the availability of net proceeds, which are gross cash receipts remaining in the Bonneville Fund after deducting all of the costs paid by Bonneville to operate and maintain the Federal System other than those used to make payments to the United States Treasury for: (i) the repayment of the federal investment in certain transmission facilities and the power generating facilities at the Federal System Hydroelectric Projects, (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 the Federal System Hydroelectric Projects, and (iv) costs allocated to irrigation projects as are required by law to be recovered from power sales. Bonneville met its Fiscal Year 2024 payment responsibility to the United States Treasury in full and on time.

For various reasons, Bonneville's revenues from the sale of electric power and other services may vary significantly from year to year. In order to accommodate such fluctuations in revenues and to assure that Bonneville has sufficient revenues to pay the costs necessary to maintain and operate the Federal System, all non-United States Treasury cash payment obligations of Bonneville, including cash deficiency payments, if any, under the Net Billing Agreements securing the Series 2025-A/B Bonds; payments, if any, under the 1989 Letter Agreement; payments, if any, under the Direct Pay Agreements; and other operating and maintenance expenses, including the costs of transmission facility lease-purchase agreements and electric power conservation or generating resource acquisitions, have priority over payments by Bonneville to the United States Treasury. In the opinion of Bonneville's General Counsel, under federal statutes, Bonneville may make payments to the United States Treasury only from net proceeds; all other cash payments of Bonneville, including cash deficiency payments, if any, under the Net Billing Agreements securing the Series 2025-A/B Bonds; payments, if any, under the 1989 Letter Agreement; payments, if any, under the Direct Pay Agreements; and other operating and maintenance expenses, including the costs of transmission facility lease-purchase agreements and electric power conservation or generating resource acquisitions, have priority over payments by Bonneville to the United States Treasury for the costs described in (i) through (iv) in the preceding paragraph. See "—Direct Pay Agreements."

Bonneville's operating revenues include amounts equal to net billing credits if and as provided by Bonneville under the Net Billing Agreements, see "—Bonneville's Non-Federal Debt—Net Billed Bonds" and "—Direct Pay Agreements" above. Net billing credits reduce Bonneville's cash receipts by the amount of the credits. Thus, the costs payable under the Energy Northwest Net Billing Agreements for the Net Billed Projects, to the extent covered by net billing credits, are paid without regard to amounts in the Bonneville Fund. Bonneville and Energy Northwest have entered into Direct Pay Agreements under which Bonneville pays the costs of the Net Billed Projects on a current cash basis thereby reducing the use of net billing to meet the costs of the Net Billed Projects. See "—Direct Pay Agreements."

Bonneville also has obligations to reduce future amounts receivable from certain power customers that have prepaid for electric power, see "—Bonneville's Non-Federal Debt—Electric Power Prepayments," and from certain transmission customers that have provided lump sum payments to Bonneville for it to construct or install certain transmission facilities necessary to provide transmission service to the customers. The electric power prepayments involve the recognition (as credits) of the prepayments in future electric power bills by Bonneville. The credits for prepaid power will be approximately $31 million per fiscal year through Fiscal Year 2028. Transmission service credit offsets for amounts advanced to Bonneville for new transmission integration investments were $22 million in Fiscal Year 2024. Bonneville estimates that transmission service credit offsets will be $27 million in Fiscal Year 2025. The foregoing credits have the effect of reducing Bonneville's future cash revenue from the participating customers, and will reduce in the future the amount of cash in the Bonneville Fund that would otherwise be available to meet Bonneville's cash payment obligations, including lease rental payments under the Lease-Purchase Agreement.

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

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

While all amounts in the Bonneville Fund are available to pay Bonneville's costs without regard to whether such costs are Power Services' costs or Transmission Services' costs, some reserves are derived from Power Services' rates and operations and some are derived from Transmission Services' rates and operations. (As of the end of Fiscal Year 2024, approximately $591 million in Total Financial Reserves (cash, investments in United States Treasury market-based special securities and Deferred Borrowing (as defined below) were derived from Power Services' rates and operations and $707 million in Total Financial Reserves were derived from Transmission Services' rates and operations.) "Total Financial Reserves" is an unaudited metric that is not in accordance with GAAP but which Bonneville uses to reflect the amount of reliably available financial resources in or available to the Bonneville Fund to meet payment obligations. See "—Bonneville's Use of Non-GAAP Financial Metrics."

Because Bonneville's power rates are to be established to recover the costs of power operations and Bonneville's transmission rates are to be established to recover the cost of transmission operations, if Bonneville were to use Transmission Services-derived reserves to pay Power Services' costs, use of the Transmission Services' reserves would be treated as an obligation of Power Services, with the requirement that Power Services replenish any amounts of Transmission Services-derived reserves so used. Similarly, if Bonneville were to use Power Services-derived reserves to pay Transmission Services' costs, use of the Power Services' reserves would be treated as an obligation of Transmission Services, with the requirement that Transmission Services replenish any amounts of Power Services-derived reserves so used.

Bonneville's Use of Non-GAAP Financial Metrics

For a variety of reasons, Bonneville has developed and employs certain financial metrics that Bonneville management believes are descriptive of Bonneville's financial performance notwithstanding that such financial metrics are not consistent with GAAP and are unaudited.

Reserves Available for Risk. For ratemaking purposes, Bonneville uses a financial metric it refers to as "Reserves Available for Risk," or "RAR," as a measure of financial reserves. While the RAR metric is not a measure in accordance with GAAP and is unaudited, Bonneville management nonetheless believes that the RAR metric provides a sound measure of Bonneville's reserves derived (and retained) from operations. See "—Management's Discussion of Operating Results—Fiscal Year 2024." The RAR metric represents amounts in, or reliably available to, the Bonneville Fund which are generated through normal operations and excludes deposits from third parties, capital funds drawn in advance, borrowings for expenses and other amounts deemed by Bonneville not to be available for risk.

As of the end of Fiscal Year 2024, Bonneville had $823 million in RAR and a $750 million short-term credit facility (available to meet certain expenses) with the United States Treasury (the "United States Treasury Short-Term Credit Facility"). The RAR balances and the short-term borrowing facility combine to provide a cushion of liquidity for Bonneville to meet its costs in situations where revenues and expenses deviate from rate case assumptions. Bonneville forecasts and assesses uncertainty in expenses, revenues, and cash flow through the end of the rate period. Bonneville models the effect of these uncertainties on RAR and short-term liquidity, given proposed rates. This assessment yields information about several key metrics, including TPP, which is the probability that Bonneville will be able to make all payments to the United States Treasury during the rate period. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Current Bonneville Power and Transmission Rates" and "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Power Rates for Fiscal Years 2024-2025." Depending on numerous variables, assumptions and forecasts, Bonneville may establish rates that, on average, will increase (or decrease) RAR for the relevant business line in the applicable rate period in amounts that are sufficient to meet Bonneville's TPP policy. Bonneville measures RAR for both Power Services operations and Transmission Services operations.

Total Financial Reserves. "Total Financial Reserves" is a non-GAAP and unaudited metric that Bonneville uses to reflect current cash and cash equivalents. Bonneville uses the metric to reflect the amount of reliably available financial resources in or available to the Bonneville Fund to meet payment obligations. Total Financial Reserves are composed of cash, cash equivalents, and special investments held in the Bonneville Fund, and amounts that Bonneville is authorized to borrow from the United States Treasury for capital expenditures that Bonneville has incurred but has not yet borrowed for ("Deferred Borrowing"), all of which are available to meet Bonneville's current expenditure needs. To reduce overall interest expense, Bonneville may delay borrowing from the United States Treasury until necessary from a cash flow perspective (which increases the Deferred Borrowing balance). Over time, Bonneville intends to borrow such Deferred Borrowing amounts from the United States Treasury. Total Financial Reserves is comprised of RAR and RNAR. Total Financial Reserves are affected by numerous factors including revenues and expenses for the year, increases or decreases in cash and cash equivalents related to the timing of collections and payments, capital expenditures, and principal and interest payments to the United States Treasury. Bonneville does not use this metric in establishing rates; rather, Bonneville focuses on RAR. As of the end of Fiscal Year 2024, Total Financial Reserves were approximately \$1.3 billion (\$538 million of which represents Deferred Borrowing). See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Current Bonneville Power and Transmission Rates" and "—Fiscal Year 2024 Financial Results," and "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Power Rates for Fiscal Years 2024-2025."

Days Liquidity on Hand. One metric that Bonneville uses to measure the amount of liquidity relative to its ability to meet operating expenses is "Days Liquidity on Hand." Bonneville measures this using the following equation: (i) RAR plus available United States Treasury Short-Term Credit Facility (\$750 million) divided by (ii) Operating Expense (as described in footnote 1 in the "Statement of Non-Federal Debt Service Coverage and United States Treasury Payments") divided by 360. This information is unaudited.

Bonneville's Fiscal Year-End Financial Reserves
Fiscal Years 2020-2024
(Unaudited)[(1)]
(Dollars in millions)

Fiscal Year	Total Financial Reserves	Reserves Available for Risk	United States Treasury Short-Term Credit Facility	Days Liquidity on Hand
2020	\$889	\$708	\$750	295
2021	1,056	825	750	284
2022	1,834	1,511	750	380
2023	1,727	1,287	750	258
2024	1,299	823	750	189

(1) PricewaterhouseCoopers LLP, Bonneville's independent auditor, has not audited, reviewed, compiled, or applied agreed-upon procedures with respect to the financial data in this table. Accordingly, PricewaterhouseCoopers LLP does not express an opinion or any other form of assurance with respect to the financial data.

Position Management and Derivative Instrument Activities and Policies

Bonneville has adopted risk management policies and organizational structures to systematically address the management of derivative instrument activities. Policies governing transacting are overseen by an internal risk committee 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 risk to net revenue outcomes. Such policies do not authorize the use of financial instruments for purposes outside Bonneville-established strategies. Strategies are established in the context of portfolio management, as opposed to individual position/exposure management, and are subject to quantitatively-derived, hard position limits mathematically linked to Bonneville's financial metrics, such as TPP. Exceptions to established policies must be approved by Bonneville's internal risk committee before execution.

Bonneville's use of these various financial instruments is subject to regulation under the Dodd-Frank Wall Street Reform and Consumer Protection Act ("Dodd-Frank"). Dodd-Frank grants extensive discretion to applicable regulatory bodies, primarily the Commodities Futures Trading Commission ("CFTC") and the Securities and Exchange Commission ("SEC"), which have established rules regarding trading limits, and capital, reserve, and collateral requirements (primarily margin requirements).

In 2012, Bonneville approved a permanent and ongoing financial hedging program using power futures that do not require physical delivery. Such transactions require Bonneville to provide collateral through the posting of margin payments to cover the credit risk absorbed by the exchange. Margin payments can affect Bonneville's cash flows, especially if large margin payments are required. For exchange-traded power futures, failure to meet margin calls can subject a party's related agreements to immediate termination and the net mark-to-market value of the related agreements may become immediately due and payable. In contrast, Bonneville does not currently provide collateral to secure any of its related physical delivery power trading contract obligations, including over-the-counter physical delivery electric power transactions.

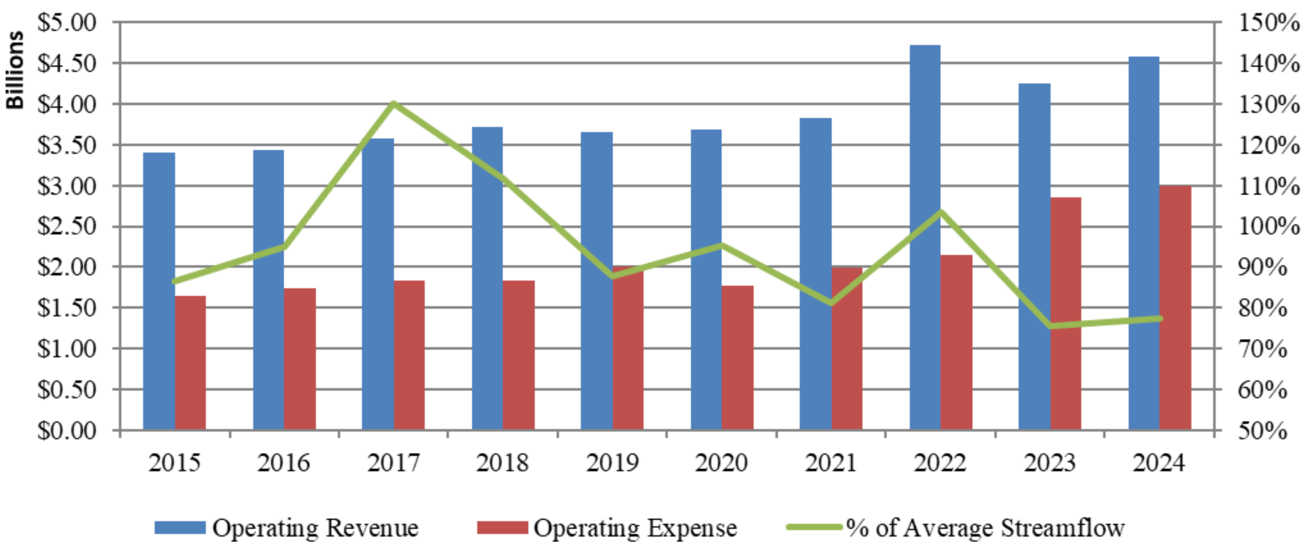
Historical Federal System Operating Revenue and Operating Expense Compared to Historical Streamflow

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

The relationship of operating revenues to operating expenses has been stable relative to wide variances in streamflow and hydro-generation. Much of this stability in revenues is attributable to the high proportion of power revenues that Bonneville derives from sales of firm power. Firm power is power expected to be produced by the Federal System under certain assumptions of Low Water Flows/Firm Water. See "POWER SERVICES—Description of the Generation Facilities of the Federal System—Federal Hydro-Generation." By contrast, Bonneville derives fewer revenues from seasonal surplus energy. In establishing the Final 2024-2025 Rates, Bonneville assumed that revenues from net seasonal surplus energy sales would average approximately $362 million per fiscal year of the rate period, assuming average streamflow. For reference, $362 million is approximately eight percent of Bonneville total operating revenues of approximately $4.6 billion (Fiscal Year 2024).

The following chart plots Bonneville's annual operating expense and operating revenues (as presented in the table entitled, "Statement of Non-Federal Debt Service Coverage and United States Treasury Payments," see "—Statement of Non-Federal Debt Service Coverage") against Federal System streamflow in the same year. The streamflow data for the relevant year are expressed as a percentage of historical average streamflow. Bonneville believes that the relative stability of operating expense and operating revenue over a wide variety of annual streamflow conditions, particularly since 2002, reflects Bonneville's accommodation of the potential variability of streamflow in virtually all of Bonneville's major functions.

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



In the preceding table, the streamflow data are based on the Federal System's Operating Year (August 1 – July 31) and the financial information is based on Bonneville's Fiscal Year (October 1 – September 30). "Operating Expense" is described in footnote 1 in the "Statement of Non-Federal Debt Service Coverage and United States Treasury Payments."

Pension and Other Post-Retirement Benefits

Federal employees associated with the operation of the Federal System participate in either the Civil Service Retirement System or the Federal Employees Retirement System. Employees may also participate in the Federal Employees Health and Benefit Program and the Federal Employee Group Life Insurance Program. All such post-retirement systems and programs are sponsored by the United States Office of Personnel Management; therefore, the accounts of the Federal System do not record any accumulated plan assets or liabilities related to the administration of such programs. Contribution amounts are paid by Bonneville to the United States Treasury and are recorded as expense during the year to which the payment relates. In Fiscal Year 2024, Bonneville made $40 million in post-retirement contributions.

Almost all of Energy Northwest's costs for its share of pension benefits relate to employment in connection with the Columbia Generating Station. To the extent that these costs arise in connection with the Energy Northwest Net Billed Projects, they have been and will be recovered under the Net Billing Agreements and borne by Bonneville. Such costs are included in "Non-Federal entities O&M—net billed" as reported in the Federal System Statement of Revenues and Expenses table below. See "BONNEVILLE FINANCIAL OPERATIONS—Bonneville's Non-Federal Debt—Net Billed Bonds."

Historical Federal System Financial Data

Federal System historical financial data for Fiscal Years 2022 through 2024 are set forth in the following "Federal System Statement of Revenues and Expenses (Unaudited)" table. Such data have been derived from the underlying financial records of the Federal System financial statements and differ therefrom in some respects in the categorization of certain costs. The audited Financial Statements of the Federal System (prepared in accordance with GAAP and provided as Appendix B-1 to the Official Statement) include accounts of Bonneville as well as those of the generating facilities that are located in the Region and owned by the Corps and Reclamation and for which Bonneville is the power marketing agency, and certain operations and maintenance costs of the Fish and Wildlife Service. Any discrepancies in totals for figures portrayed in this table are due to rounding.

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Federal System Statement of Revenues and Expenses
(Unaudited)[14]

As of Sept. 30 – Dollars in millions	**2024**	**2023**	**2022**
Operating Revenues:			
Sales of electric power —			
Sales within the Northwest Region —			
Northwest Publicly-Owned Utilities [1]	$2,102	$1,924	$2,144
Direct Service Industrial Customers	4	3	4
Northwest Investor-Owned Utilities	403	332	304
Sales outside the Northwest Region [2]	575	614	1,043
Book-outs [3]	(77)	(94)	(63)
Total Sales of Electric Power	3,007	2,779	3,432
Transmission Sales [4]	1,233	1,153	1,119
Fish Credits and other Revenues [5]	329	316	171
Total Operating Revenues	4,569	4,248	4,722
Operating Expenses:			
Bonneville O&M [6]	1,344	1,259	1,212
Purchased Power [3]	1,023	977	359
Corps, Reclamation, and Fish & Wildlife Service O&M [7]	494	457	410
Non-Federal entities O&M — net billed [8]	301	311	274
Non-Federal entities O&M — non-net billed [9]	49	35	33
Total Operations and Maintenance	3,211	3,039	2,288
Depreciation, Amortization and Accretion	871	849	841
Residential Exchange [10]	275	267	267
Total Operating Expenses	4,357	4,154	3,396
Net Operating Revenues	212	94	1,326
Interest Expense and Other Income/Expense:			
Appropriated Funds	39	42	41
Long-term debt – net billed	213	210	207
Long-term debt – non-net billed	226	191	224
Capitalization Adjustment [11]	(65)	(65)	(65)
Irrigation Assistance	8		
Other, net[12]	(21)	14	(20)
Allowance for funds used during construction	(57)	(42)	(25)
Total Interest Expense and Other Income/Expense[13]	344	351	362
Net Revenues/(Expenses)	**$ (132)**	**$ (257)**	**$ 964**
Total Sales (annual average megawatts) (Net of Residential Exchange Program and excluding Canadian Entitlement Return)	8,291	8,676	10,861

[1] This customer group includes Preference Customers (municipalities, public utility districts, electric cooperatives, and tribal utilities in the Region) and federal agencies.

(2) In general, revenues from Sales outside the Northwest Region are derived from seasonal surplus energy and firm long-term sales. The amount of firm power that can be produced by the Federal System and marketed by Bonneville to meet firm load obligations is based on assumptions related to a lower water period on record for the last 30 years of the 90-year historical streamflow record or the Columbia River basin referred to herein as "Low Water Flows at the 10th Percentile/Firm Energy." The availability of seasonal surplus energy that Bonneville has to market is highly dependent upon the occurrence of streamflow in the Columbia River basin that is greater than would occur under Low Water Flows at the 10th Percentile/Firm Energy. In almost all years, except when streamflow is near Low Water Flows at the 10th Percentile/Firm Energy, the amount of seasonal surplus energy that Bonneville exports is greater than firm sales exports. Revenues from seasonal surplus energy sales are also affected by the prices Bonneville can obtain for the sale of energy in short-term energy markets, which is influenced by the cost other producers incur to generate energy and the price of fuel (in particular, natural gas) used to generate the energy.

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

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

(5) Bonneville also receives certain revenues from sources apart from power sales and the provision of transmission services. These revenues relate primarily to fish and wildlife payment credits (also referred to as "4(h)(10)(C) credits") that reduce Bonneville's United States Treasury repayment obligation. Such credits are provided on the basis of estimates and forecasts and later are adjusted when actual data are available. The amount of such credits was approximately $112 million, $258 million, and $258 million in Fiscal Years 2022, 2023, and 2024, respectively. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Fish and Wildlife—Federal Repayment Offsets for Certain Fish and Wildlife Costs Borne by Bonneville."

(6) Bonneville O&M expenses include operations and maintenance expenditures for the Federal Transmission System, and other Bonneville functions such as Bonneville's power marketing, and fish and wildlife programs. Bonneville O&M as included herein reflects a mix of cash payments and accrued amounts, which, when aggregated with other line items presented herein, are consistent with amounts reported in the audited financial statements of the Federal System.

(7) Corps, Reclamation, and Fish and Wildlife Service O&M expenses include Federal System operations and maintenance expenditures of the Corps, Reclamation and the Fish and Wildlife Service. Amounts shown represent cash payments. An offsetting adjustment for accrued amounts is included in Bonneville O&M (see footnote (6) above).

(8) The Non-Federal entities O&M – net billed expense includes the operations 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 operations 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) See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services" and "—Residential Exchange Program." Bonneville's aggregate 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 2024, the Residential Exchange Program payments were $275 million.

(11) The capitalization adjustment represents the annual recognition of the reduction in principal realized from refinancing Federal Appropriations Repayment Obligations under a federal law enacted in 1996.

(12) Other, net primarily includes dividend income and realized gains and losses associated with the Columbia Generating Station decommissioning and site restoration trust funds gains and losses incurred due to the early extinguishment of debt.

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

(14) PricewaterhouseCoopers LLP, Bonneville's independent auditor, has not audited, reviewed, compiled, or applied agreed-upon procedures with respect to the financial data in this table. Accordingly,

PricewaterhouseCoopers LLP does not express an opinion or any other form of assurance with respect to the financial data.

Management's Discussion of Operating Results

Fiscal Year 2024

In Fiscal Year 2024, Bonneville made its scheduled United States Treasury payments on time and in full for the 41st consecutive year. Bonneville finished the fiscal year with Total Financial Reserves of $1.3 billion, which is a decrease of approximately 25 percent from the prior fiscal year.

At the end of Fiscal Year 2024, aggregate Bonneville RAR was $823 million, a decrease of approximately 36 percent from the prior fiscal year. See "—Bonneville's Use of Non-GAAP Financial Metrics." RAR for Power Services operations was $507 million, a decrease of $416 million from the prior fiscal year-end balance of $923 million, and RAR for Transmission Services operations was $316 million, a decrease of $47 million from the prior fiscal year-end balance of $363 million.

In Fiscal Year 2024, Federal System net revenues were negative $132 million, an increase of approximately $125 million from net revenues of negative $257 million in Fiscal Year 2023.

In Fiscal Year 2024, Power Services and Transmission Services consolidated gross sales, excluding the effects of bookouts, were $4.2 billion, which is an increase of approximately $309 million from consolidated gross sales of $3.9 million in Fiscal Year 2023. Power Services' gross sales increased $211 million, or approximately seven percent, in Fiscal Year 2024 compared to Fiscal Year 2023, primarily due to: (i) a $284 million revenue increase driven by a diminished impact of the Power Reserves Distribution Clause to revenues in Fiscal Year 2024 ($165.4 million revenue reduction vs. $350 million reduction in Fiscal Year 2023) and (ii) offset by $55 million decrease in sales due to warmer weather decreasing load shaping revenues. A key metric that Bonneville uses to measure year-to-year changes in river runoff is the amount of water (as measured in MAF) flowing through The Dalles Dam, which is the second dam upriver from the mouth of the Columbia River. January 2024 through July 2024 runoff volume at The Dalles Dam was 79 MAF, which is a decrease of 1 MAF over the same period in Fiscal Year 2023. The full Fiscal Year 2024 volume finished at 102 MAF, an increase of 2 MAF from Fiscal Year 2023, and below the historical average (1929-2018) of 134 MAF.

In Fiscal Year 2024, Transmission Services sales increased by $81 million compared to Fiscal Year 2023, primarily due to increase in revenue from EIM (defined below), ancillary services, network integration, and point-to-point long-term services.

In Fiscal Year 2024, United States Treasury credits were consistent with the credits in Fiscal Year 2023 at $262 million.

In Fiscal Year 2024, Operating Expenses increased $203 million, or approximately 5 percent, compared to Fiscal Year 2023. In Fiscal Year 2024, Operations and Maintenance Expense increased $135 million, or six percent, compared to Fiscal Year 2023 primarily due to: (i) a $30 million increase related to Bonneville's participation in Cal-ISO's Western Energy Imbalance Market ("EIM") a real-time bulk power trading market system that automatically finds the lowest-cost energy to serve real-time customer demand (resolving imbalances while maintaining reliability) across a wide geographic area (under the EIM, utilities maintain control over their assets and remain responsible for balancing requirements while sharing in the costs and benefits that the market produces for participants) due to the extreme cold snap experienced during January 2024; (ii) a $27 million increase in Corps and Reclamation expenses primarily due to increased labor costs; (iii) a $25 million increase in transmission maintenance expenses due to an increase in maintenance work performed throughout various Asset Management programs; (iv) a $10 million increase to control center support, mainly due to inflation and new support contracts; (v) a $9 million increase in third-party wheeling expenses due to a Fiscal Year 2024 rate increase; (vi) a $7 million scheduled increase in costs related to the Residential Exchange Program; (vii) a $7 million increase to Fish and Wildlife program expenses due to a planned increase in the amount of work performed when compared to the same period of Fiscal Year 2023; (viii) a $5 million increase in Fish and Wildlife costs in connection with the Fiscal Year 2022 Power Reserves Distribution Clause decision, in which

Bonneville committed to funding certain expenditures in advance of when they were originally expected to be made; (ix) a $5 million increase in operation and maintenance cost related to the Cowlitz Falls Hydroelectric Project due to a planned increase to cover inflation and additional project work; (x) a $3 million increase as a result of more work performed at certain Lower Snake River Compensation Plan facilities; (xi) a $30 million increase to various Transmission, Power, and Enterprise Services program costs primarily due to increases in personnel costs; and (xii) an offsetting $23 million decrease to conservation purchases due to a reduction in work performed.

In Fiscal Year 2024, Purchased Power expense, including the effects of bookouts, increased $46 million, or approximately 5 percent, compared to Fiscal Year 2023 primarily due to: (i) a $152 million increase in purchased power driven by the January 2024 cold snap, where Bonneville was a net purchaser of power at extremely high prices and (ii) an offset of $106 million decrease in the amount owed to British Columbia Hydro ("BC Hydro"), a Canadian electric utility owned by the province of British Columbia, under certain water storage agreements compared to amounts owed to BC Hydro in Fiscal Year 2023.

In Fiscal Year 2024, Depreciation, Amortization, and Accretion increased $22 million compared to Fiscal Year 2023, primarily due to an increase in utility plant assets in service.

In Fiscal Year 2024, total Net Interest Expense and Other Income/Expense decreased $7 million compared to Fiscal Year 2023, primarily due to a decrease in Other, net compared to the prior year.

Fiscal Year 2023

In Fiscal Year 2023, Bonneville made its scheduled United States Treasury payments on time and in full for the 40th consecutive year. Bonneville finished the fiscal year with Total Financial Reserves of $1.7 billion, which is a decrease of approximately six percent from the prior fiscal year.

At the end of Fiscal Year 2023, aggregate Bonneville RAR was $1.3 billion, a decrease of approximately 15 percent from the prior fiscal year. See "—Bonneville's Use of Non-GAAP Financial Metrics." RAR for Power Services operations was $923 million, a decrease of $321 million from the prior fiscal year-end balance of $1.2 billion, and RAR for Transmission Services operations was $363 million, an increase of $96 million from the prior fiscal year-end balance of $267 million.

In Fiscal Year 2023, Federal System net revenues were negative $257 million, a decrease of approximately $1.2 billion from net revenues of $964 million in Fiscal Year 2022.

In Fiscal Year 2023, Power Services and Transmission Services consolidated gross sales, excluding the effects of bookouts, were $4 billion, which is a decrease of approximately $595 million from consolidated gross sales of $4.6 billion in Fiscal Year 2022. Power Services' gross sales decreased $622 million, or approximately 18 percent, in Fiscal Year 2023 compared to Fiscal Year 2022, primarily due to: (i) a $344 million decrease in revenues from seasonal surplus energy sales due to lower streamflows and less hydroelectric generation when compared to Fiscal Year 2022 and (ii) a $278 million decrease in firm power sales due to a planned decrease in revenues as a result of the Power RDC (which reduced Fiscal Year 2023 firm sales by $350 million). A key metric that Bonneville uses to measure year-to-year changes in river runoff is the amount of water (as measured in MAF) flowing through The Dalles Dam, which is the second dam upriver from the mouth of the Columbia River. January 2023 through July 2023 runoff volume at The Dalles Dam was 80 MAF, which is a decrease of 26 MAF over the same period in Fiscal Year 2022. The full Fiscal Year 2023 volume finished at 100 MAF, an increase of 37 MAF from Fiscal Year 2022, and below the historical average (1929-2018) of 134 MAF.

In Fiscal Year 2023, Transmission Services sales increased by $35 million compared to Fiscal Year 2022, primarily due to an increase in the sale of point-to-point long-term transmission service.

In Fiscal Year 2023, United States Treasury credits increased by $145 million compared to Fiscal Year 2022, primarily due to higher volumes of replacement power at higher market prices.

In Fiscal Year 2023, Operating Expenses increased $758 million, or approximately 22 percent, compared to Fiscal Year 2022. In Fiscal Year 2023, Operations and Maintenance Expense increased $132 million, or six percent, compared to Fiscal Year 2022 primarily due to: (i) a $40 million increase in Columbia Generating Station plant costs since Fiscal Year 2023 was a refueling year (refueling and maintenance expense are typically higher in refueling years); (ii) a $32 million increase in Corps and Bureau expenditures primarily due to increased labor costs, (iii) a $23 million increase in energy conservation purchase due to additional work being completed in Fiscal Year 2023; (iv) an $11 million increase in Fish and Wildlife program expenditures primarily due to additional work performed in Fiscal Year 2023 when compared to the prior year; (v) a $9 million increase for reimbursable work performed for third parties due to an increase in large generator interconnection and line and load interconnection work performed in Fiscal Year 2023; (vi) a $6 million net increase related to an annual settlement paid to the Confederated Tribes of the Colville Reservation; (vii) a $4 million increase related to Transmission System Development Planning and Analysis; and (viii) a $7 million increase in various other Transmission Services and Power Services program costs primarily due to increases in personnel costs.

In Fiscal Year 2023, Purchased Power expense, including the effects of bookouts, increased $618 million, or approximately 172 percent, compared to Fiscal Year 2022 primarily due to: (i) a $585 million increase in Purchased Power due to dry conditions and lower water available for hydroelectric generation and higher market prices and (ii) a $33 million increase in the amount owed to BC Hydro, a Canadian electric utility owned by the province of British Columbia, under certain water storage agreements compared to amounts owed to BC Hydro in Fiscal Year 2022.

In Fiscal Year 2023, Depreciation, Amortization, and Accretion increased $8 million compared to Fiscal Year 2022, primarily due to an $11 million increase in depreciation expense due to increased utility plant assets in service compared to the prior year. This increase was partially offset by a $4 million decrease in amortization expense due to asset retirements in Fiscal Year 2023.

In Fiscal Year 2023, total Net Interest Expense and Other Income/Expense decreased $11 million compared to Fiscal Year 2022, primarily due to an increase in interest income due to higher interest rates earned on short-term investments in United States Treasury securities compared to the prior year.

Fiscal Year 2022

In Fiscal Year 2022, Bonneville made its scheduled United States Treasury payments on time and in full for the 39th consecutive year. Bonneville finished the fiscal year with Total Financial Reserves of $1.8 billion, which is an increase of approximately 74 percent from the prior fiscal year.

At the end of Fiscal Year 2022, aggregate Bonneville RAR was $1.5 billion, an increase of approximately 83 percent from the prior fiscal year. See "—Bonneville's Use of Non-GAAP Financial Metrics." RAR for Power Services operations was $1.2 billion, an increase of $628 million from the prior fiscal year-end balance of $617 million, and RAR for Transmission Services operations was $267 million, an increase of $58 million from the prior fiscal year-end balance of $209 million.

In Fiscal Year 2022, Federal System net revenues were $964 million, an increase of approximately $566 million from net revenues of $398 million in Fiscal Year 2021.

In Fiscal Year 2022, Power Services and Transmission Services consolidated gross sales, excluding the effects of bookouts, were $4.6 billion, which is an increase of approximately $858 million from consolidated gross sales of $3.7 billion in Fiscal Year 2021. Power Services' gross sales increased $754 million, or approximately 28 percent, in Fiscal Year 2022 compared to Fiscal Year 2021, primarily due to an increase in revenues from seasonal surplus energy sales due to higher market prices than forecast in the rate case. A key metric that Bonneville uses to measure year-to-year changes in river runoff is the amount of water (as measured in MAF) flowing through The Dalles Dam, which is the second dam upriver from the mouth of the Columbia River. January 2022 through July 2022 runoff volume at The Dalles Dam was 106 MAF, which is an increase of 24 MAF over the same period in Fiscal Year 2021. The full Fiscal Year 2022 volume finished at 137 MAF, an increase of 30 MAF from Fiscal Year 2021, and above the historical average of 134 MAF.

In Fiscal Year 2022, Transmission Services sales increased $104 million compared to Fiscal Year 2021, primarily due to an increase in the sale of point-to-point long-term transmission service.

In Fiscal Year 2022, United States Treasury credits increased by $22 million compared to Fiscal Year 2021, primarily due to higher volumes of replacement power at higher market prices.

In Fiscal Year 2022, Operating Expense increased $168 million, or approximately five percent, compared to Fiscal Year 2021. In Fiscal Year 2022, Operations and Maintenance Expense increased $43 million, or two percent, compared to Fiscal Year 2021 primarily due to: (i) a $25 million increase in enterprise services general and administrative expenses to support various Power Services and Transmission Services programs; (ii) a $17 million scheduled increase to Residential Exchange Program costs, (iii) a $17 million increase in settlement charges related to Bonneville's participation in EIM; (iv) a $15 million increase in Corps expenditures primarily due to fish mitigation studies and higher labor and materials costs due to inflation; (v) an $11 million increase in third-party wheeling expenses due to increased power sales and the need to transmit more electric power to customers not directly connected to the Federal Transmission system in Fiscal Year 2022; and (vi) a $10 million net increase to various other Transmission Services and Power Services program costs. The various increases in Operations and maintenance expense were partially offset by: (i) a $37 million decrease in Columbia Generating Station plant costs since Fiscal Year 2022 was not a refueling year (refueling and maintenance expense are typically higher in refueling years) and (ii) a $15 million decrease in energy conservation expenses due to less work performed in Fiscal Year 2022 when compared to Fiscal Year 2021.

In Fiscal Year 2022, Purchased Power expense, including the effects of bookouts, increased $111 million, or approximately 45 percent, compared to Fiscal Year 2021 primarily due to: (i) a $101 million increase in Purchased Power due to higher market prices and (ii) a $10 million increase in the amount owed to BC Hydro, a Canadian electric utility owned by the province of British Columbia, under certain water storage agreements compared to amounts owed to BC Hydro in Fiscal Year 2021.

In Fiscal Year 2022, Depreciation, Amortization, and Accretion increased $14 million compared to Fiscal Year 2021, primarily due to an $8 million increase in amortization related to the Columbia River Fish Mitigation program.

In Fiscal Year 2022, total Net Interest Expense and Other Income/Expense increased $164 million compared to Fiscal Year 2021, primarily due to a $182 million decrease in Other Income.

Statement of Non-Federal Debt Service Coverage

The "Statement of Non-Federal Debt Service Coverage and United States Treasury Payments" below uses the "Federal System Statement of Revenues and Expenses (Unaudited)" to develop a non-federal project debt service coverage ratio ("Non-Federal Debt Service Coverage Ratio"), which demonstrates how many times total non-federal project debt service is covered by net funds available for non-federal project debt service. Net funds available for non-federal debt service is defined as total operating revenues less operating expenses. Net funds available for non-federal project debt service less total non-federal project debt service yields the amount available for payment to the United States Treasury. This Non-Federal Debt Service Coverage Ratio does not reflect the actual priority of payments or distinctions between cash payments and credits under Bonneville's net billing obligations under the Net Billing Agreements. Any discrepancies in totals for figures portrayed in this table are due to rounding.

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Statement of Non-Federal Debt Service Coverage and United States Treasury Payments (Unaudited)[13]

As of Sept. 30 – Dollars in millions	**2024**	**2023**	**2022**
Total Operating Revenues	$4,569	$4,248	$4,722
Less: Operating Expenses[1]	2,992	2,848	2,144
Net Funds Available to meet Non-Federal Debt Service Obligations	1,577	1,400	2,578
Less: Non-Federal Debt Service Obligations			
Non-Federal Projects[2]	411	229	194
Lease-Purchase Program[3]	146	130	132
Electric Power Prepayments [4]	31	31	31
Total Non-Federal Debt Service Obligations	588	390	357
Revenue Available for Treasury	$989	$1,010	$2,221
Non-Federal Debt Service Coverage Ratio[5]	2.7x	3.6x	7.2x
Non-Federal Project Debt Service Plus Operating Expense Coverage Ratio[6]	1.3x	1.3x	1.9x
Amount Allocated for Payment to Treasury[7]:			
Corps and Reclamation O&M[8]	$494	$457	$410
Net Interest Expense and Other Income/Expense[9]	344	351	362
Non-Federal Projects[2, 9]	(194)	(198)	(187)
Lease-Purchase Program[3, 9]	(54)	(58)	(59)
Electric Power Prepayments[4, 9]	(6)	(7)	(8)
Capitalization Adjustment[10]	65	65	65
Allowance for Funds Used During Construction [11]	36	25	15
Amortization of Federal Principal[12]	500	741	694
Total Amount Allocated for Payment to Treasury[7]	$1,185	$1,376	$1,292

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

(2) Includes debt service (principal and interest) for generating resources acquired by Bonneville under Net Billing Agreements or other capitalized contracts. Non-net billed debt service amounted to $9 million, $9 million, and $9 million for Fiscal Years 2022, 2023, and 2024 respectively. 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 interest expense portion of the Non-Federal Projects as shown here is a reduction of Amount Allocated for Payment to Treasury.

(3) 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 interest expense portion of the Lease-Purchase Program included here is a reduction of Amount Allocated for Payment to Treasury. A portion of the Lease-Purchase Program Debt Service includes amounts related to the repayment of principal on maturing bonds.

(4) 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 interest expense portion of the Electric Power Prepayments included here is a reduction of Amount Allocated for Payment to Treasury. In Fiscal Year 2013, Bonneville received $340 million from certain Preference Customers as one-time prepayments of portions of their future power bills through Fiscal Year 2028. In return the customers will receive credits in future power bills. The aggregate amount of the credits is $2.55 million per month through Fiscal Year 2028. In Fiscal Year 2024, Bonneville provided credits on Preference Customers' bills in an aggregate amount of $31 million. Of this amount, $6 million is accounted for as Net Interest Expense and $25 million is accounted for as the repayment of principal. See "BONNEVILLE FINANCIAL OPERATIONS—Bonneville's Non-Federal Debt—Electric Power Prepayments."

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

<u>Total Operating Revenues-Operating Expense (Footnote 1)</u>

Non-Federal Projects + Lease-Purchase Program + Electric Power Prepayments

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

<u>Total Operating Revenues</u>

Operating Expense (Footnote 1) + Non-Federal Projects + Lease-Purchase Program + Electric Power Prepayments

(7) In contrast to the "Total Amount Allocated for Payment to Treasury," Bonneville's actual payments to the United States Treasury in Fiscal Years 2022, 2023, and 2024 were $951 million, $1.02 billion, and $792 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."

(8) Amounts shown are calculated on a cash basis and include direct operations and maintenance payments to the Corps, Reclamation, and Fish and Wildlife Service for Fiscal Years 2022, 2023, and 2024. See "—Direct Funding of Federal System Operations and Maintenance Expense."

(9) Net Interest Expense as reported in the audited financial statements of the Federal System (included as Appendix B-1 to the Official Statement) includes certain interest associated with obligations to Non-Federal entities. Amounts shown are calculated on an accrual basis.

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

(11) The Allowance for Funds Used During Construction includes, among other things, Bonneville's portion of the interest during the construction period for Federal System investments funded by borrowings from the United States Treasury. For clarity, none of the related interest expense for the Lease-Purchase Program is reflected in Allowance for Funds Used During Construction.

(12) Regional Cooperation Debt actions enabled Bonneville to prepay $114 million in Federal Obligations in Fiscal Year 2024, $401 million in Fiscal Year 2023, and $334 million in Fiscal Year 2022, in addition to the amounts otherwise scheduled for repayment in Bonneville's rates. The effect of these prepayments and the extension of Energy Northwest debt resulted in atypically high Non-Federal Debt Service Coverage Ratios.

(13) PricewaterhouseCoopers LLP, Bonneville's independent auditor, has not audited, reviewed, compiled, or applied agreed-upon procedures with respect to the financial data in this table. Accordingly, PricewaterhouseCoopers LLP does not express an opinion or any other form of assurance with respect to the financial data.

Management's Discussion of Unaudited Results for the Six Months ended March 31, 2025

Total operating revenues were approximately $2.3 billion through the second quarter of Fiscal Year 2025 ("Fiscal Year 2025 Second Quarter"), a decrease of $212 million compared to operating revenues of approximately $2.5 billion for the six months ended March 31, 2024 ("Fiscal Year 2024 Second Quarter"). Consolidated gross sales for Power and Transmission Services, including the effect of bookouts, were approximately $2.1 billion through Fiscal Year 2025 Second Quarter, which was similar to consolidated gross sales of approximately $2.2 billion through Fiscal Year 2024 Second Quarter. ("Bookouts" are a reflection of accounting guidance associated with energy activities that are settled other than by the physical delivery of power and are reported on a "net" basis in both operating revenues and purchased power expense. The accounting treatment for book-outs has no effect on net revenues, cash flows, or margins.)

Power Services gross sales, including the effect of bookouts, were $1.5 billion through Fiscal Year 2025 Second Quarter, a decrease of $75 million as compared to Power Services gross sales, including the effect of bookouts, of $1.6 billion through Fiscal Year 2024 Second Quarter.

Transmission sales and other revenues were $631 million through Fiscal Year 2025 Second Quarter, a decrease of $8 million as compared to Transmission sales of $639 million through Fiscal Year 2024 Second Quarter. The decrease in Transmission sales was primarily related to a $45 million decrease in EIM revenues compared to the same period for fiscal year 2024, offset by an increase in point-to-point and other revenues of $36 million.

United States Treasury credits for fish and wildlife mitigation decreased by $128.2 million when compared to Fiscal Year 2024 Second Quarter due to lower volumes of purchased power in Fiscal Year 2025 Second Quarter.

Through Fiscal Year 2025 Second Quarter, total operating expenses were $2 billion, a $440 million decrease when compared to total operating expenses of $2.5 billion through Fiscal Year 2024 Second Quarter.

Operations and Maintenance Expense increased by $97 million in Fiscal Year 2025 Second Quarter when compared to Fiscal Year 2024 Second Quarter primarily due to: (i) a $54 million increase in Columbia Generating Station costs due to Fiscal Year being a refueling year, (ii) a $16 million increase in Corps costs due to a greater amount of work completed when compared to the prior period; and (iii) a $22 million increase to various Transmission, Enterprise Services and Power program costs primarily due to increases in personnel costs. Purchased power expense, including the effects of bookouts, decreased by $543 million primarily due to a $542 million decrease in power purchases due to lower volumes of power purchases and at lower market prices when compared to Fiscal Year 2024 Second Quarter.

Depreciation, Amortization and Accretion was approximately $440 million through Fiscal Year 2025 Second Quarter, which is similar to Depreciation, Amortization and Accretion of approximately $433 million through Fiscal Year 2024 Second Quarter.

Total Interest Expense and Other Income, Net decreased by $156 million in Fiscal Year 2025 Second Quarter when compared to Fiscal Year 2024 Second Quarter. Other, net changed by $169 million compared to Fiscal Year 2024 Second Quarter due to the $166 million gain recognized in connection with the early extinguishment of U.S. Treasury debt. Interest Income decreased by $12 million compared to Fiscal Year 2024 Second Quarter as a result of lower amounts of U.S. Treasury market-based special securities due to lower cash balances coupled with lower interest rates received from U.S. Treasury.

For further information regarding Fiscal Year 2025 Second Quarter unaudited results, see Appendix B-2—"FEDERAL SYSTEM UNAUDITED FINANCIAL INFORMATION FOR THE SIX MONTHS ENDED MARCH 31, 2025."

BONNEVILLE LITIGATION

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

Columbia River ESA Litigation

Since 2001, NOAA Fisheries and the Action Agencies have been involved in continuous litigation with the National Wildlife Federation ("NWF") and other plaintiffs in the District Court over a succession of biological opinions relating to listed anadromous salmonid species of the Columbia and Snake rivers. This litigation began with a challenge to the 2000 Columbia River System Biological Opinion and has resulted in a series of revised biological opinions (including the 2004 Biological Opinion, the 2008 Biological Opinion, the 2010 Supplemental Biological Opinion, and the 2014 Supplemental Biological Opinion, each of which attempted to correct the deficiencies identified by the court) and subsequent challenges under the ESA, the APA, and NEPA.

In January 2014, NOAA Fisheries issued the 2014 Columbia River System Supplemental Biological Opinion. In February 2014, the Action Agencies each signed a decision document to implement the biological opinion. In May 2014, American Rivers and other plaintiffs filed a petition in the Ninth Circuit Court challenging Bonneville's record of decision. In July 2014, NWF and other plaintiffs challenged NOAA Fisheries' biological opinion and the Corps' and Reclamation's decision documents in District Court, and the State of Oregon intervened as a plaintiff in this litigation in October 2014. In both the District Court and Ninth Circuit Court actions, plaintiffs alleged that the 2014 Columbia River System Supplemental Biological Opinion and related decisions violate certain provisions of the ESA, NEPA, and the APA. These lawsuits were similar to previous challenges of past biological opinions, with the exception of one additional claim under NEPA challenging the Action Agencies' failure to prepare a new environmental impact statement for their adoption and implementation of the Reasonable and Prudent Alternative actions in the biological opinion. The Ninth Circuit Court originally issued an order staying the petition against Bonneville pending resolution of the District Court action. Shortly after the issuance by the District Court of the May 4, 2016 order described immediately below, the lawsuit in the Ninth Circuit Court was voluntarily dismissed.

On May 4, 2016, the District Court issued a ruling on the ESA challenges to the 2014 Columbia River System Supplemental Biological Opinion and the NEPA challenge. The District Court concluded that the Corps and Reclamation violated NEPA and identified a number of deficiencies with the 2014 Columbia River System Supplemental Biological Opinion, including that the approach used by NOAA Fisheries to determine whether the listed species "are trending toward recovery" is arbitrary and capricious, that the 2014 Columbia River System Supplemental Biological Opinion relies on habitat restoration benefits that "are too uncertain and do not allow any margin of error," and that the 2014 Columbia River System Supplemental Biological Opinion "fails to properly analyze the effects of climate change." See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Fish and Wildlife—The Endangered Species Act."

On July 6, 2016, the District Court issued an order directing that a new biological opinion under the ESA be prepared on or before December 31, 2018, a new environmental impact statement under NEPA be prepared on or before March 26, 2021, and that the federal agencies' records of decision documenting decisions on how to implement the ESA, which will be informed by analyses provided in the environmental impact statement, shall be issued on or before September 24, 2021. On April 17, 2018, the District Court issued an order adjusting the deadline for the new biological opinion and environmental impact statement to March 26, 2021. See "POWER SERVICES—Certain Statutes and Other Matters Affecting Bonneville's Power Services—Fish and Wildlife—The Endangered Species Act."

On January 9, 2017, plaintiffs filed requests for injunctive relief with the District Court seeking increased spring spill at eight Federal Snake River and Columbia River System dams and a halt to spending by the Corps of Engineers on certain ongoing and future capital projects at the four lower Snake River dams. In April 2017, the District Court issued an opinion and order granting in part and denying in part the motions for injunction with respect to spill and capital project funding. In its April 2017 ruling, the District Court ordered "increased spill" but delayed implementation of changes to system operations "until the spring 2018 migration season" in order to allow time for the parties to develop a "spill implementation plan and proposed injunction order," either through consensus or by court resolution following subsequent briefings and hearings. On June 2, 2017, the federal defendants filed a notice of appeal from the April 3, 2017 initial injunction ruling. On January 8, 2018, the District Court issued a final order directing increased spill for the spring 2018 fish passage season (approximately April-June 2018) at all eight Federal Snake River and Columbia River System dams identified in the injunction motions and certain fish monitoring actions.

The Ninth Circuit Court issued an opinion on April 2, 2018, affirming the District Court's spill and fish monitoring injunctions. Spill for fish passage under the District Court's injunction order began at the eight Snake and Columbia River Federal System dams in April 2018.

On December 14, 2018, Action Agencies, defendant intervenor State of Washington, plaintiff the State of Oregon and amicus the Nez Perce Tribe entered into an agreement in which the Action Agencies agreed to specified spring spill operations in 2019 and 2020, and a cap on the related costs of the agreed spring spill operations borne by Bonneville, in exchange for a pause in litigation on the biological opinion. The agreement set the costs to Bonneville of the 2019 and 2020 spring spill at no more than the cost of 2018 spring spill operations. Because the agreement changed the proposed action, NOAA Fisheries issued a new biological opinion (referred to herein as the "2019 Columbia River System Biological Opinion") incorporating the agreed to spring spill operations, effective April 1, 2019 until a new action could be adopted through records of decision related to the ongoing CRSO NEPA process.

On September 28, 2020, the Action Agencies signed a joint record of decision adopting the Preferred Alternative in the Final CRSO EIS and adopting the 2020 Columbia River System Biological Opinions. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Developments Relating to the Endangered Species Act."

In December 2020, a coalition of fishing and environmental groups and two Indian tribes filed complaints in the Ninth Circuit Court challenging Bonneville's CRSO Environmental Impact Statement Record of Decision alleging that Bonneville's decision violated certain provisions of the ESA, NEPA, APA, and the Northwest Power Act. These cases were consolidated on January 13, 2021. On August 18, 2021, Bonneville filed a certified index and certification for administrative record. On January 19, 2021, the environmental groups filed a motion for leave to file a supplemental complaint in the District Court case alleging that the Final CRSO EIS, the 2020 Columbia River System Biological Opinions, and related decisions by the Corps and Reclamation violate certain provisions of the ESA and NEPA, as well as the APA and the Northwest Power Act, as well as challenging NOAA Fisheries under the ESA, which was granted the same day. Four Indian tribes and the states of Oregon, Idaho, and Montana have intervened in the District Court litigation, and the State of Washington as well as several Indian tribes are involved as unaligned amicus curiae. There is substantial overlap between the Ninth Circuit Court and District Court cases. On August 24, 2021, the federal government received a letter from NWF requesting discussions on a resolution of the cases without continued litigation by first addressing 2022 operations and then holding discussions on a long-term comprehensive solution. The parties sought an extension to the briefing schedule from the District Court to allow for these discussions to occur. The federal government entered into discussions with NWF, the State of Oregon, and the Nez Perce Tribe on October 1, 2021. The federal government agreed to 2022 operations with these entities and filed a motion on October 21, 2021, with the District Court to stay proceedings for the preliminary injunction and summary judgment motions and provide notice of the agreed upon 2022 operations. One plaintiff-aligned amicus filed an objection to the stay. The District Court granted the stay until July 31, 2022, denied the objection, denied without prejudice and leave to renew the preliminary injunction motions, and ordered a joint status report on the long-term discussions by July 31, 2022. The Ninth Circuit granted administrative closure of that case to align with the stay in the District Court. The litigation stay was extended until August 31, 2023, at the District Court and until September 8, 2023 in the Ninth Circuit. As part of the continued stay, the parties agreed on 2023 fish passage operations, which are largely consistent with 2022 fish passage operations. The parties have filed two status reports with the District Court (on November 2, 2022 and January 31, 2023) in compliance with the District Court's stay order and one status update with the Ninth Circuit Court (on March 15, 2023).

On September 28, 2023, the Department of Justice filed a motion to voluntarily dismiss certain claims brought by the Coeur d'Alene Tribe and Spokane Tribe of Indians based on a 20-year mediated settlement agreement entered into by Bonneville with other federal agencies. In this stay agreement Bonneville committed to fund $200 million in annual payments of $10 million over 20 years, among other things, in exchange for the dismissal of these complaints. The District Court granted this motion on September 28, 2023. See "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Developments Relating to the Endangered Species Act."

On October 31, 2023, the Department of Justice filed a notice with the District Court providing an update that the federal defendants and certain participants in this litigation had developed a proposed package of actions and commitments. This proposed package was discussed with the other regional sovereigns and litigation parties through a confidential conferral process. Based on the December 2023 Agreement, the federal defendants, the National Wildlife Federation Plaintiffs and the states of Oregon and Washington, and the Yakama Nation, the Nez Perce Tribe, the Confederated Tribes of the Warm Springs Indian Reservation, and the Confederated Tribes of the Umatilla Indian Reservation, filed a joint stay motion asking the District Court to pause the litigation for five years, through December 2028. Subsequent to filing the joint stay motion, the states of Idaho and Montana, the Public Power Council, Northwest River Partners and Inland Ports and Navigation Group filed oppositions to the stay motion. On February 8, 2024, the U.S. District Court for the District of Oregon granted a stay through December 13, 2028 (with potential for an additional five years), and on February 23, 2024, the U.S. Court of Appeals for the Ninth Circuit dismissed without prejudice litigation regarding the CRSO EIS and associated consultation. The signatories to the agreement that gave rise to the motions for stay and dismissal are now implementing the commitments in the agreement. The signatories submitted a Joint Annual Report to the District Court on January 14, 2025, in accordance with the December 2023 Agreement.

On December 18, 2024, the Corps and Reclamation issued a NOI to SEIS. This NOI started the scoping period for the SEIS, which invites all affected federal, state, and local agencies, tribes, other interested parties, and the public to participate in the NEPA process during development of the SEIS. The scoping period was expected to end May 9; however, the Corps and Reclamation rescinded the NOI and are expected to issue a new NOI in the coming weeks. The scope of the new NOI is unknown at this time. For the ESA consultations associated with the CRSO EIS, the Action Agencies have reinitiated consultation with the U.S. Fish and Wildlife Service due to recent listings and proposed listings of species. The Action Agencies are evaluating whether reinitiation of ESA consultation with NOAA Fisheries is necessary.

There are three consolidated petitions currently filed with the Ninth Circuit Court challenging Bonneville's authority to sign on to the December 2023 Agreement. This matter is in administrative closure through June 2, 2025, while the parties participate in mediation. Bonneville is unable to predict the outcome of this litigation or its potential impact on the December 2023 Agreement and associated spill operations.

EPA Clean Water Act Litigation

On February 23, 2017, Columbia Riverkeeper and other plaintiffs filed suit against the EPA in Washington Federal District Court in Seattle alleging violations of the Clean Water Act – Section 303(d) and the APA. The Washington Federal District Court granted, in part, the plaintiffs' claims directing EPA to approve or disapprove of what the Washington Federal District Court determined was a constructive submission of a Total Maximum Daily Allowance ("TMDL") for temperature in the Columbia and Snake Rivers by Oregon and Washington within 30 days of the ruling. The Washington Federal District Court then determined that if EPA disapproves of the constructive TMDL it must issue a new TMDL 30 days from that date. The United States appealed the Washington Federal District Court's ruling to the Ninth Circuit Court and received a stay on its ruling. EPA and the plaintiffs agreed to an expedited review of the case by the Ninth Circuit Court. EPA filed its opening brief on April 12, 2019. Plaintiffs' answer was filed on May 10, 2019 and EPA's reply was filed on June 7, 2019. Oral arguments were held in the Ninth Circuit Court case in August 2019. On December 20, 2019, the Ninth Circuit issued its opinion affirming the district court's decision that the states had constructively submitted a temperature TMDL, which triggered EPA's duty to act under the Clean Water Act and develop and issue a temperature TMDL. The EPA issued the temperature TMDL for public review and comment on May 18, 2020. After reviewing and considering comments, the EPA reissued the TMDL on August 13, 2021. As part of the Clean Water Act regulations on TMDLs, EPA transmitted the re-issued TMDL to the states of Oregon and Washington, so the states could begin developing implementation plans. Currently, the Oregon Department of Environmental Quality and Washington Department of Ecology have not begun developing the implementation plans, but Bonneville will work closely with these state agencies once this process begins.

Bonneville is unable to predict the outcome of these implementation plans but it could lead to potential changes in the operation and configuration of the Federal System Hydroelectric Projects.

Holiday Farm Fire ("HFF") Litigation

Over the Labor Day holiday weekend in September 2020, the HFF started in the vicinity of Eugene, Oregon. The fire burned over 170,000 acres, causing property damage, personal injuries, and one known death. As a result of the HFF, and pursuant to the requirements of the FTCA, Bonneville received more than 2,000 administrative tort claims, totaling more than $2 billion.

Various law firms, representing plaintiffs affected by the HFF, have filed federal complaints. One of the law firms also filed an inverse condemnation (5th Amendment taking) complaint in the United States Court of Federal Claims in Washington, DC.

Federal Tort Claims Act

In January and February of 2024, three separate suits under the FTCA were filed in the United States District Court for the District of Oregon. The cases have been consolidated. All settlements or court judgments from tort claims are paid by the United States Judgment Fund, not the Bonneville Fund.

Plaintiffs allege that Bonneville had a duty to operate, monitor, maintain, and repair its electric utility infrastructures to ensure that it did not cause fires. Plaintiffs allege the duty required Bonneville to deenergize its power lines during the dry and windy conditions when the HFF started. Plaintiffs also allege that Bonneville breached its duty by failing to remove vegetation that impacted power lines and led to the HFF.

Plaintiffs allege that two Bonneville electric utility customers, Lane Electric Cooperative ("LEC") and Eugene Water & Electric Board ("EWEB"), also breached a duty of care and thereby caused the HFF. They are codefendants in the lawsuit, and they have also asserted cross-claims against the United States based on alleged negligence by Bonneville.

On August 2, 2024, the United States moved to dismiss the lawsuits because it is protected by discretionary immunity. The discretionary function exception ("DFE") shields United States agencies from liability where the agency had discretion to take (or not take) the disputed action. Here, no policy required Bonneville to de-energize its lines or remove any specific trees or other vegetation. Accordingly, the United States argues, it is immune from suit under the DFE.

Oral argument on the United States' motion to dismiss is set for August 29. 2025.

Inverse Condemnation

On December 12, 2023, the U.S. Department of Justice was served with an inverse condemnation claim related to the HFF. The complaint is based on the same operative facts as the claims under the FTCA. Plaintiffs in the Inverse Condemnation suit are a subset of the plaintiffs in the FTCA suits, and many of the claims related to property damage overlap with the FTCA claims.

The complaint alleges that the HFF resulted in a taking of plaintiffs' property without just compensation and is therefore compensable under the 5^{th} Amendment of the United States Constitution.

On February 14, 2024, the United States moved to dismiss this case. On September 30, 2024, the Court denied the United States' motion to dismiss.

On October 15, 2024, the United States moved to stay the case because of its overlap with tort claims against the United States related to the HFF that are pending in United States District Court for the District of Oregon. On December 12, 2024, the Court denied the motion to stay. The United States answered on January 2, 2025.

The parties are currently conferring regarding discovery, proposed case schedule, and related matters. A Joint Proposed Status Report is due April 30, 2025.

Bonneville is unable to predict with certainty whether any settlements or judgments arising from this suit would be paid from the United States Judgment Fund or the Bonneville Fund. Although Bonneville does not have a track record with source of payment for any past inverse condemnation settlements or judgments, similar suits against other federal agencies have been paid from the Judgment Fund, and the United States Treasury has indicated the Judgment Fund would be available to pay settlements or judgments arising from this case.

Fiscal Year 2022 Power RDC Challenge

Based on the Power Services' RAR balance of $1.2 billion at September 30, 2022 and total RAR of $1.5 billion at September 30, 2022, a Power RDC triggered in the amount of $500 million for application to certain Power Services rate levels in Fiscal Year 2023. On January 6, 2023, the Administrator determined that 70 percent or $350 million of the Power RDC would be applied to reduce Power rates from December 2022 through September 2023. Credits were applied to power customer bills through September 2023. In addition to the rate reduction implemented in Fiscal Year 2023, $100 million of the Power RDC amount was held in Total Financial Reserves for debt reduction in Fiscal Year 2023 and $50 million was held in Total Financial Reserves to fund certain fish and wildlife expenses on an accelerated basis (in advance of when such expenditures were originally expected to be made).

On April 5, 2023, Idaho Conservation League, Great Old Broads for Wilderness, and Idaho Rivers United filed suit against Bonneville in the Ninth Circuit Court petitioning for review of Bonneville's Fiscal Year 2022 Power RDC decision. Petitioners seek the same relief as in the Fiscal Year 2022-2023 Rates Challenge discussed above: (i) a decision to set aside Bonneville's Fiscal Year 2022 Power RDC decision and remand to Bonneville with instructions to revisit the decision in a manner that complies with Bonneville's duties to fish and wildlife under the Northwest Power Act and (ii) other declaratory and injunctive relief as necessary to remedy their injuries including an order requiring Bonneville to provide increased funding for fish and wildlife mitigation efforts during the remand period.

In April 2023, the Public Power Council, Northwest Requirements Utilities, and Alliance of Western Energy Consumers moved to intervene in this case. On May 11, 2023, the Ninth Circuit Court issued an order administratively closing this case until November 13, 2023 and suspended the briefing schedule pending the outcome of the Fiscal Year 2022-2023 Rates challenge. The case has been reopened and petitioners filed their opening brief on March 15, 2024. Bonneville's answering brief was filed on May 3, 2024. Briefing concluded on June 7, 2024 with petitioners' reply brief. Oral argument was held in December 2024. The parties await a decision from the court.

Fiscal Year 2023 Power RDC Challenge

On March 18, 2024, Idaho Conservation League, Great Old Broads for Wilderness, and Idaho Rivers United filed suit against Bonneville in the Ninth Circuit Court petitioning for review of Bonneville's Fiscal Year 2023 Power RDC decision, which was issued on December 23, 2023. For details related to the Fiscal Year 2023 Power RDC, see "CERTAIN DEVELOPMENTS RELATING TO BONNEVILLE—Current Bonneville Power and Transmission Rates." Petitioners seek: (i) a decision to set aside Bonneville's Fiscal Year 2023 Power RDC decision and remand to Bonneville with instructions to revisit the decision in a manner that complies with Bonneville's duties to fish and wildlife under the Northwest Power Act and (ii) other declaratory and injunctive relief as necessary to remedy their injuries including an order requiring Bonneville to provide increased funding for fish and wildlife mitigation efforts during the remand period.

In April 2024, the Public Power Council, Northwest Requirements Utilities, and Alliance of Western Energy Consumers moved to intervene in this case. Petitioners' opening brief was due on June 28, 2024. Bonneville's answering brief and any intervenor briefs were due on August 16, 2024. Briefing concluded on September 6, 2024 with petitioners' reply brief. Oral argument was held in December 2024. The parties await a decision from the court.

Rates Litigation Generally

Bonneville's rates are frequently the subject of litigation in the Ninth Circuit Court. 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.

Miscellaneous Litigation

From time to time, Bonneville may be involved in numerous other cases and arbitration proceedings, including land, contract, employment, billing disputes, 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

Opinion

We have audited the accompanying combined financial statements of the Federal Columbia River Power System (the "FCRPS"), which comprise the combined balance sheets as of September 30, 2024 and 2023, and the related combined statements of revenues and expenses and of cash flows for the years ended September 30, 2024, 2023 and 2022, including the related notes (collectively referred to as the "combined financial statements").

In our opinion, the accompanying combined financial statements present fairly, in all material respects, the financial position of the FCRPS as of September 30, 2024 and 2023, and the results of its operations and its cash flows for the years ended September 30, 2024, 2023 and 2022 in accordance with accounting principles generally accepted in the United States of America.

Basis for Opinion

We conducted our audit in accordance with auditing standards generally accepted in the United States of America (US GAAS). Our responsibilities under those standards are further described in the Auditors' Responsibilities for the Audit of the Combined Financial Statements section of our report. We are required to be independent of the FCRPS and to meet our other ethical responsibilities, in accordance with the relevant ethical requirements relating to our audit. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Responsibilities of Management for the Combined Financial Statements

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

In preparing the combined financial statements, management is required to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the FCRPS' ability to continue as a going concern for one year after the date the combined financial statements are available to be issued.

Auditors' Responsibilities for the Audit of the Combined Financial Statements

Our objectives are to obtain reasonable assurance about whether the combined financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion. Reasonable assurance is a high level of assurance but is not absolute assurance and therefore is not a guarantee that an audit conducted in accordance with US GAAS will always detect a material misstatement when it exists. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control. Misstatements are considered material if there is a substantial likelihood that, individually or in the aggregate, they would influence the judgment made by a reasonable user based on the combined financial statements.

In performing an audit in accordance with US GAAS, we:

- Exercise professional judgment and maintain professional skepticism throughout the audit.
- Identify and assess the risks of material misstatement of the combined financial statements, whether due to fraud or error, and design and perform audit procedures responsive to those risks. Such procedures include examining, on a test basis, evidence regarding the amounts and disclosures in the combined financial statements.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the FCRPS' internal control. Accordingly, no such opinion is expressed.
- Evaluate the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluate the overall presentation of the combined financial statements.
- Conclude whether, in our judgment, there are conditions or events, considered in the aggregate, that raise substantial doubt about the FCRPS' ability to continue as a going concern for a reasonable period of time.

We are required to communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit, significant audit findings, and certain internal control-related matters that we identified during the audit.

PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
November 1, 2024

PricewaterhouseCoopers LLP, 805 SW Broadway, Suite 800, Portland, OR 97205
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Federal Columbia River Power System
Combined Balance Sheets
As of September 30

(Millions of Dollars)

	2024	2023
Assets		
Utility plant and nonfederal generation		
Completed plant	**$ 22,235.9**	$ 21,674.7
Accumulated depreciation	**(8,604.9)**	(8,316.0)
Net completed plant	**13,631.0**	13,358.7
Construction work in progress	**2,236.4**	1,733.1
Net utility plant	**15,867.4**	15,091.8
Nonfederal generation	**3,410.0**	3,380.0
Net utility plant and nonfederal generation	**19,277.4**	18,471.8
Current assets		
Cash and cash equivalents	**1,412.0**	2,037.9
Accounts receivable, net of allowance	**95.4**	84.7
Accrued unbilled revenues	**348.2**	282.7
Materials and supplies, at average cost	**140.5**	121.0
Prepaid expenses	**81.0**	67.9
Total current assets	**2,077.1**	2,594.2
Other assets		
Regulatory assets	**4,153.4**	4,272.4
Nonfederal nuclear decommissioning trusts	**623.5**	479.5
Deferred charges and other	**169.6**	222.0
Total other assets	**4,946.5**	4,973.9
Total assets	**$ 26,301.0**	$ 26,039.9

The accompanying notes are an integral part of these financial statements.

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

(Millions of Dollars)

	2024	2023
Capitalization and Liabilities		
Capitalization and long-term liabilities		
Accumulated net revenues	**$ 5,456.9**	$ 5,589.1
Debt		
Federal appropriations	**1,697.1**	1,597.6
Borrowings from U.S. Treasury	**5,846.7**	5,584.8
Nonfederal debt	**6,779.3**	6,885.6
Total capitalization and long-term liabilities	**19,780.0**	19,657.1
Commitments and contingencies (See Note 14 to 2024 Audited Financial Statements)		
Current liabilities		
Debt		
Borrowings from U.S. Treasury	**114.0**	199.0
Nonfederal debt	**521.9**	505.5
Accounts payable and other	**869.1**	885.0
Total current liabilities	**1,505.0**	1,589.5
Other liabilities		
Regulatory liabilities	**1,522.4**	1,543.2
IOU exchange benefits	**1,062.8**	1,299.2
Asset retirement obligations	**1,118.2**	1,015.1
Deferred credits and other	**1,312.6**	935.8
Total other liabilities	**5,016.0**	4,793.3
Total capitalization and liabilities	**$ 26,301.0**	$ 26,039.9

The accompanying notes are an integral part of these financial statements.

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

(Millions of Dollars)

	2024	2023	2022
Operating revenues			
Sales	**$ 4,306.8**	$ 3,985.6	$ 4,604.6
U.S. Treasury credits	**262.4**	262.3	116.9
Total operating revenues	**4,569.2**	4,247.9	4,721.5
Operating expenses			
Operations and maintenance	**2,463.1**	2,328.0	2,195.8
Purchased power	**1,023.2**	977.0	358.7
Depreciation, amortization and accretion	**870.9**	848.9	841.0
Total operating expenses	**4,357.2**	4,153.9	3,395.5
Net operating revenues	**212.0**	94.0	1,326.0
Interest expense and other income, net			
Interest expense	**457.2**	448.4	417.7
Irrigation assistance	**8.4**	-	-
Allowance for funds used during construction	**(56.8)**	(42.0)	(24.9)
Interest income	**(43.9)**	(69.4)	(10.6)
Other, net	**(20.7)**	14.0	(20.3)
Total interest expense and other income, net	**344.2**	351.0	361.9
Net revenues (expenses)	**(132.2)**	(257.0)	964.1
Accumulated net revenues, beginning of year	**5,589.1**	5,859.6	4,912.6
Irrigation assistance	**-**	(13.5)	(17.1)
Accumulated net revenues, end of year	**$ 5,456.9**	$ 5,589.1	$ 5,859.6

The accompanying notes are an integral part of these financial statements.

Federal Columbia River Power System

Combined Statements of Cash Flows

For the Years Ended September 30

(Millions of Dollars)

	2024	2023	2022
Cash flows from operating activities			
Net revenues (expenses)	**$ (132.2)**	$ (257.0)	$ 964.1
Adjustments to reconcile net revenues to cash provided by operations:			
Depreciation, amortization and accretion	**870.9**	848.9	841.0
Boardman to Hemingway non-cash net loss	**-**	27.9	-
Other	**(28.7)**	(20.4)	(13.4)
Changes in:			
Receivables and unbilled revenues	**(78.8)**	132.5	(180.3)
Materials and supplies	**(19.5)**	(11.6)	0.1
Prepaid expenses	**(13.1)**	(18.9)	(9.5)
Accounts payable and other	**151.8**	329.1	334.1
Regulatory assets and liabilities	**70.3**	(217.2)	(7.4)
IOU exchange benefits	**(236.4)**	(214.8)	(208.2)
Nonfederal nuclear decommissioning trusts	**(128.9)**	(60.0)	105.3
Other assets and liabilities	**89.3**	237.4	(49.0)
Net cash provided by operating activities	**544.7**	775.9	1,776.8
Cash flows from investing activities			
Investment in utility plant, including AFUDC	**(1,169.2)**	(851.9)	(693.8)
Proceeds from sale of utility plant	**2.6**	3.2	13.2
U.S. Treasury securities:			
Purchases	**-**	(250.0)	(1,250.0)
Maturities	**-**	750.0	750.0
Deposits to nonfederal nuclear decommissioning trusts	**(15.1)**	(4.9)	(4.7)
Lease-purchase trust funds:			
Deposits to	**(1.5)**	-	-
Receipts from	**4.3**	-	-
Net cash used for investing activities	**(1,178.9)**	(353.6)	(1,185.3)
Cash flows from financing activities			
Federal appropriations:			
Proceeds	**126.3**	80.5	43.1
Repayment	**(26.8)**	(123.8)	(5.0)
Borrowings from U.S. Treasury:			
Proceeds	**650.0**	722.0	744.0
Repayment	**(473.1)**	(616.9)	(694.2)
Nonfederal debt:			
Repayment	**(294.7)**	(160.4)	(208.5)
Customers:			
Net advances for construction	**48.6**	84.2	20.3
Repayment of funds used for construction	**(22.0)**	(20.1)	(21.0)
Irrigation assistance	**-**	(13.5)	(17.1)
Net cash provided by (used for) financing activities	**8.3**	(48.0)	(138.4)
Net increase (decrease) in cash, cash equivalents and restricted cash	**(625.9)**	374.3	453.1
Cash, cash equivalents and restricted cash at beginning of year	**2,046.1**	1,671.8	1,218.7
Cash, cash equivalents and restricted cash at end of year	**$ 1,420.2**	$ 2,046.1	$ 1,671.8
Less: Restricted cash at end of year, reported in Deferred charges and other	**8.2**	8.2	8.8
Cash and cash equivalents at end of year	**$ 1,412.0**	$ 2,037.9	$ 1,663.0
Supplemental disclosures:			
Cash paid for interest, net of amount capitalized	**$ 490.7**	$ 404.2	$ 396.4
Significant noncash activities:			
Nonfederal debt increase	**$ 1,012.5**	$ 674.9	$ 705.6
Nonfederal debt decrease	**$ (802.3)**	$ (489.9)	$ (507.4)
Nonfederal debt cost of issuance	**$ (5.4)**	$ (3.4)	$ (3.0)
Increase in Nonfederal generation asset	**$ 59.1**	$ -	$ -

The accompanying notes are an integral part of these financial statements.

Notes to Financial Statements

1. Summary of Significant Accounting Policies

ACCOUNTING PRINCIPLES

Combination of entities

The Federal Columbia River Power System (FCRPS) financial statements combine the accounts of the Bonneville Power Administration (BPA) with the accounts of the Pacific Northwest generating facilities of the U.S. Army Corps of Engineers (USACE) and the Bureau of Reclamation (Reclamation). The FCRPS combined financial statements also include the operations and maintenance costs of the U.S. Fish and Wildlife Service for the Lower Snake River Compensation Plan (USFWS LSRCP) facilities. Consolidated with BPA is a variable interest entity (VIE) of which BPA is the primary beneficiary and from which BPA leases certain transmission facilities. (See Note 8, Debt and Appropriations, and Note 9, Variable Interest Entities.)

BPA is a separate and distinct entity within the U.S. Department of Energy; the USACE is part of the U.S. Department of Defense; and Reclamation and U.S. Fish and Wildlife Service are part of the U.S. Department of the Interior. Each of the combined entities is separately managed, but the facilities are operated as an integrated power system with the financial results combined as the FCRPS. BPA is a self-funding federal power marketing administration that purchases, transmits and markets power for the FCRPS. While the costs of USACE, Reclamation and USFWS LSRCP projects serve multiple purposes, only the power portion of total project costs are assigned to the FCRPS through cost allocation processes. All intracompany and intercompany accounts and transactions have been eliminated from the FCRPS financial statements.

FCRPS financial statements are prepared in accordance with generally accepted accounting principles (GAAP) of the United States of America. FCRPS financial statements also reflect the Uniform System of Accounts (USoA) as prescribed for electric public utilities by the Federal Energy Regulatory Commission (FERC). FCRPS accounting policies also reflect other specific legislation and directives issued by U.S. government agencies. All U.S. government properties and income are tax exempt.

Use of estimates

The preparation of FCRPS financial statements in conformity with GAAP 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 FCRPS 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 submitted by BPA and reviewed by FERC. FERC's review is based on BPA statutes that include a requirement that rates must be sufficient to ensure repayment of the federal investment in the FCRPS over a reasonable number of years after first meeting BPA's other costs. After the final FERC approval, BPA's rates may be reviewed by the United States Court of Appeals for the Ninth Circuit (Ninth Circuit Court) if challenged by parties involved in the rate proceedings. Petitions seeking such review must be filed within 90 days of the final FERC approval. The Ninth Circuit Court may either confirm or reject a rate proposed by BPA. BPA's rates are not structured to provide a rate of return on its assets. Rates for the two-year BP-24 rate period began on Oct. 1, 2023, and will conclude on Sept. 30, 2025.

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 5, Effects of Regulation.)

Utility plant

Utility plant is stated at original cost and includes federal system hydro generation assets (i.e., Pacific Northwest generating facilities of the USACE and Reclamation) as well as transmission and other assets. 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 certain overhead items; and an allowance for funds used during construction (AFUDC). Maintenance, repairs and replacements of items determined to be less than major units of property are charged as incurred to Operations and maintenance in the Combined Statements of Revenues and Expenses. When utility plant is retired, the original cost and any net proceeds from the disposition are charged to accumulated depreciation. (See Note 3, Utility Plant and Nonfederal Generation.)

Depreciation, amortization and accretion

Depreciation of the original cost of generation plant is computed using straight-line methods based on estimated average service lives of the various classes of property. 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 average service lives of the various classes of property. Periodically BPA conducts a depreciation study on transmission and general plant assets. BPA updates depreciation rates based on updated asset lives and net salvage, which considers cost of removal and salvage proceeds. The estimated net cost of removal is included in depreciation expense. (See Note 3, Utility Plant and Nonfederal Generation.)

In the event removal costs associated with transmission plant are expected to exceed salvage proceeds, a reclassification of this negative salvage is made from accumulated depreciation to a regulatory liability. As actual removal costs are incurred, the associated regulatory liability is reduced. (See Note 5, Effects of Regulation.)

Amortization expense relates to nonfederal generation assets, certain regulatory assets and finance lease right-of-use assets. (For further discussion see Note 3, Utility Plant and Nonfederal Generation; Note 5, Effects of Regulation and Note 4, Leases.)

Accretion expense is recorded throughout the fiscal year in connection with a periodic increase to the Columbia Generating Station (CGS) asset retirement obligation (ARO) liability to reflect the passage of time. (For further discussion see Note 6, Asset Retirement Obligations.)

Allowance for funds used during construction

AFUDC represents the estimated cost of interest on financing the construction of new assets. AFUDC is calculated based on the construction work in progress balance and on Lease-Purchase Program trust fund balances held for construction purposes. (See Note 7, Deferred Charges and Other.) AFUDC is charged to the capitalized cost of the utility plant asset and is a reduction of Interest expense and other income, net in the Combined Statements of Revenues and Expenses.

AFUDC is capitalized at one rate for construction funded substantially by BPA and at another rate for USACE and Reclamation construction funded by congressional appropriations. (See Note 3, Utility Plant and Nonfederal Generation.) The BPA rate is determined based on the weighted-average cost of borrowing for certain types of debt and deferred credits that are related to BPA construction activity. The rate for appropriated funds is provided at the beginning of each year to BPA by the U.S. Treasury.

Nonfederal generation

BPA is party to long-term contracts for BPA to acquire all of the generating capability of Energy Northwest's CGS nuclear power plant and Lewis County PUD's (Public Utility District's) Cowlitz Falls Hydroelectric Project. CGS is a nonfederal nuclear power plant owned and operated by Energy Northwest, a joint operating agency of the state of Washington. The current license termination dates for CGS and the Cowlitz Falls Project are in December 2043 and May 2036, respectively. BPA has acquired the output of CGS and the Cowlitz Falls Project through December 2043 and June 30, 2032, respectively. These contracts require BPA to meet all of the facilities' operating, maintenance and debt service costs. Operations and maintenance expense for these projects are recognized based upon annual total project cash funding requirements, which vary from year to year.

Nonfederal generation assets on the Combined Balance Sheets are amortized on a straight-line basis, with the amortization expense included in Depreciation, amortization and accretion in the Combined Statements of Revenues and Expenses. CGS is amortized through the current license termination date in 2043. Beginning in fiscal year 2024, in alignment with the BP-24 rate case, the amortization period for the Cowlitz Falls Project changed from the license termination date in 2036 to align with the period in which BPA is contracted to receive the output of the Cowlitz Falls Project, which ends in 2032. As of Sept. 30, 2024, and 2023, the CGS Nonfederal generation asset also includes approximately $98 million of prepaid nuclear fuel purchased by Energy Northwest that management anticipates CGS will begin using in 2031. Future amortization expense is expected to occur over the years in which the fuel will be used.

Cash and cash equivalents

Cash amounts for the FCRPS include cash and cash equivalents in the Bonneville Power Administration Fund (Bonneville Fund) within the U.S. Treasury and cash from certain unexpended appropriations of the USACE and Reclamation related to the FCRPS. As of Sept. 30, 2024, and 2023, cash amounts also include cash held in a margin account with BPA's financial futures broker, which BPA could access within one day. Cash equivalents in the Bonneville Fund consist of investments in non-marketable market-based special securities issued by the U.S. Treasury with original 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 relates to the loss that might occur as a result of counterparty non-performance.

BPA's accounts receivable are spread across a diverse group of customers throughout the western United States and Canada, and include consumer-owned utilities (COUs), investor-owned utilities (IOUs), power marketers, wind generators and others. BPA's accounts receivable exposure is generally from large and stable counterparties and does not represent a significant concentration of credit risk. During fiscal years 2024, 2023 and 2022, BPA experienced no material losses as a result of any customer defaults or bankruptcy filings.

BPA mitigates credit risk by reviewing counterparties for creditworthiness, establishing credit limits and monitoring credit exposure. To further manage credit risk, BPA obtains credit support, such as letters of credit, parental guarantees, and cash in the form of prepayments, deposits or escrow funds, from some counterparties. BPA monitors counterparties for changes in financial condition and regularly updates credit reviews. (See Note 12, Risk Management and Derivative Instruments.)

Allowance for doubtful accounts

Management reviews accounts receivable 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 allowance is not material to the financial statements.

Derivative instruments

Derivative instruments consist primarily of forward electricity contracts and are measured at fair value and recognized on the Combined Balance Sheets as either Deferred charges and other or as Deferred credits and other. Changes in fair value are deferred as either Regulatory assets or Regulatory liabilities on the Combined Balance Sheets in accordance with regulated operations accounting guidance. Recognition of these contracts in the Combined Statements of Revenues and Expenses occurs in Sales or Purchased power when the contracts settle. BPA elects the normal purchases and normal sales exception under derivatives and hedging accounting guidance for certain contracts that require physical delivery, are expected to be used or sold in the normal course of business and meet the derivative accounting definition of a capacity contract. The FCRPS does not apply hedge accounting. (See Note 12, Risk Management and Derivative Instruments.)

Fair value

Carrying amounts of current assets and current liabilities approximate fair value based on the short-term nature of these instruments. Fair value measurements are applied to certain financial assets and liabilities and to determine fair value disclosures in accordance with GAAP. 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 quoted forward prices for commodities, time value, volatility factors, current market and contractual prices for underlying instruments, market interest rates and yield curves, and credit spreads, as well as other relevant economic measures. (See Note 12, Risk Management and Derivative Instruments and Note 13, Fair Value Measurements.)

Operating revenues and net revenues

Sales include estimated unbilled revenues. (See Note 2, Revenue Recognition.) Net revenues over time are committed to payment of operational obligations, including debt for both operating and non-operating nonfederal projects, debt service on bonds BPA issues to the U.S. Treasury, the repayment of federal appropriations for the FCRPS, and the payment of certain irrigation costs.

U.S. Treasury credits

U.S. Treasury credits represent nonpower-related costs that BPA recovers from the U.S. Treasury in accordance with certain laws. (See Note 2, Revenue Recognition.)

Purchased power

Purchased power expense represents wholesale power purchases that are meant to augment the FCRPS resource pool to meet loads and obligations. In addition, this expense includes the costs of certain water storage agreements between BPA and third parties. Purchased power excludes operations and maintenance expenses associated with CGS and the Cowlitz Falls Hydroelectric Project, and with certain contracts for renewable resources that BPA management considers part of the FCRPS resource pool.

Interest expense

Interest expense includes interest associated with nonfederal debt related to operating or terminated nonfederal generation assets, bonds issued by BPA to the U.S. Treasury, the unpaid balance of federal appropriations scheduled for repayment, and other nonfederal debt and certain liabilities. In addition, interest expense includes the amortization of bond premiums, discounts and costs of issuance. Reductions to interest expense include the amortization of a capitalization adjustment regulatory liability. (See Note 5, Effects of Regulation.)

Interest income

Interest income includes interest earnings on market-based special securities in the Bonneville Fund and interest earnings from other sources.

Other, net

Other, net primarily includes dividend income and realized gains and losses associated with the nonfederal nuclear decommissioning trusts for CGS. In addition, gains and losses incurred because of early debt extinguishment are recorded to this caption. In fiscal year 2023, Other, net also included $31 million net non-cash expense related to the "Boardman to Hemingway (B2H) with Transfer Service" transaction in March 2023. For further information on the B2H transaction, see Note 7, Deferred Charges and Other.

Residential Exchange Program

In order to provide residential and small farm customers of qualifying regional utilities, primarily IOUs, access to power benefits from the FCRPS, Congress established the Residential Exchange Program (REP) in Section 5(c) of The Pacific Northwest Electric Power Planning and Conservation Act (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. No physical power is transmitted. Rather, the REP functions exclusively as a net financial transaction; wherein, higher-cost utilities participating in the REP receive benefits payments from BPA and entirely pass-through these monies to their eligible residential and small farm customer. REP costs are forecast for each year of the rate period and included in the revenue requirement for establishing BPA's power rates. REP costs are recognized when incurred and are included in Operations and maintenance in the Combined Statements of Revenues and Expenses.

In fiscal year 2011, BPA signed the 2012 Residential Exchange Program Settlement Agreement (2012 REP Settlement Agreement), resolving disputes related to the REP. The 2012 REP Settlement Agreement provided for fixed "Scheduled Amounts" payable to the IOUs through fiscal year 2028. (See Note 10, Residential Exchange Program.)

Pension and other postretirement benefits

Federal employees associated with the operation of the FCRPS participate in either the Civil Service Retirement System or the Federal Employees Retirement System. Employees may also participate after retirement in the Federal Employees Health and Benefit Program and the Federal Employees Group Life Insurance Program. All such postretirement systems and programs are sponsored by the U.S. Office of Personnel Management; therefore, the FCRPS financial statements do not include accumulated plan assets or liabilities related to the administration of such programs. As part of BPA's scheduled payment each year to the U.S. Treasury for bonds and other purposes, BPA makes contributions to cover the estimated annual unfunded portion of FCRPS pension and postretirement benefits. These contribution amounts are paid to the U.S. Treasury and are recorded as Operations and maintenance in the Combined Statements of Revenues and Expenses during the year to which the payment relates.

SUBSEQUENT EVENTS

Management has performed an evaluation of events and transactions for potential FCRPS recognition or disclosure through Nov. 1, 2024, which is the date the financial statements were issued.

In October 2024, an agreement was signed to extend an existing Columbia Basin Fish Accord through Sept. 30, 2034. (See Note 14, Commitments and Contingencies.)

2. Revenue Recognition

DISAGGREGATED REVENUE

Years ended Sept. 30 - millions of dollars	2024	2023	2022
Sales			
Power			
Firm	$ 2,034.6	$ 1,817.0	$ 2,095.0
Surplus[1]	972.5	962.4	1,337.0
Transmission	1,178.6	1,097.2	1,070.4
Other[2]	121.1	109.0	102.2
Sales	$ 4,306.8	$ 3,985.6	$ 4,604.6
U.S. Treasury credits[3]	262.4	262.3	116.9
Total operating revenues[4]	$ 4,569.2	$ 4,247.9	$ 4,721.5

[1] Surplus revenue includes $300.7 million, $227.9 million, and $575.2 million of derivative commodity contracts and related operational hedging activity for fiscal years 2024, 2023 and 2022, respectively, which are not considered revenue from contracts with customers under ASC 606. For further information, see additional disclosure below.
[2] Other revenue includes $56.5 million, $42.6 million and $41.7 million for fiscal years 2024, 2023 and 2022, respectively, that are not classified as revenue from contracts with customers under ASC 606. For further information, see additional disclosure below.
[3] U.S. Treasury credits are not classified as revenue from contracts with customers under ASC 606. For further information, see additional disclosure below.
[4] Revenue from contracts with customers was $3,949.6 million, $3,715.1 million and $3,987.7 million for fiscal years 2024, 2023 and 2022, respectively.

SALES

A substantial majority of FCRPS revenues is from rate-regulated sales of power and transmission products and services. All revenues are from contracts with customers except for U.S. Treasury credits, derivatives and certain other revenues as shown in the table above. BPA establishes rates for its power and transmission services in a formal rate proceeding. The power and transmission rate schedules and general rate schedule provisions establish the rates, billing determinants, and rate provisions applicable to all BPA power and transmission contracts. Charges for services specified in the rate schedules and their provisions represent the amount billed by BPA for the goods or services used and purchased by its customers.

BPA has elected to apply the right-to-invoice practical expedient to FCRPS rate-regulated revenues from power and transmission services. Amounts invoiced correspond directly with the value to the customers for energy or services provided by the FCRPS reporting entities. Therefore, revenue from power and transmission sales, which includes billed and estimated unbilled amounts, is recognized over time upon the delivery of energy or services to the customers. The customers receive and benefit from the value of power and transmission at the time of delivery. Payments for amounts billed by BPA are generally due from customers within 20 days of billing. There are no material significant financing components.

"Firm" power consists of energy, capacity, or both, that is guaranteed to be available to the customer at all times during the period covered by a contract, except by reason of certain uncontrollable forces or service interruption provisions. The Northwest Power Act obligates BPA to meet a utility customer's firm consumer load net of the customer's resources used to serve its load. In addition, BPA sells firm power to other federal agencies and to a direct service industrial customer within the region for their direct consumption. The vast majority of firm power sold by BPA in fiscal years 2024, 2023 and 2022 was to preference customers, which make long-term power purchases from BPA at cost-based rates to meet their retail loads in the region. Preference customers are qualifying public utility districts, municipalities, consumer-owned electric cooperatives, and tribal utilities within the region. BPA's current power sales agreements with preference customers are in effect through fiscal year 2028.

"Surplus" power consists of energy and capacity that can be provided on an hourly or other short-term basis that is surplus to meeting certain firm loads as defined in the Northwest Power Act. BPA often describes the sale of surplus power as secondary sales. Most surplus power is sold to Pacific Northwest and California markets under short-term power sales that allow for flexible negotiated prices, or under longer-term contracts. The availability of surplus power depends primarily on precipitation and reservoir storage levels, performance of the Columbia Generating Station, BPA's firm power load obligations and other factors. Secondary revenues from the sale of surplus power are highly variable and depend on market conditions and the resulting prices. Amounts disclosed are net of bookouts, which occur when sales and purchases are scheduled with the same counterparty on the same path for the same hour.

Also included within Surplus sales are revenues from derivative commodity contracts in scope of ASC 815, Derivatives and Hedging, which are not considered revenue from contracts with customers under ASC 606. Derivative revenues are reported net of bookouts and primarily source from certain secondary power contracts that involve derivative instruments. (For further information on derivatives, see Note 1, Summary of Significant Accounting Policies, and Note 12, Risk Management and Derivative Instruments.)

"Transmission" revenues consist primarily of revenue for the transmission of power on BPA's network within and through the BPA service area. Point-to-point long-term contracts exceeding one year comprise the majority of network revenues and allow customers to move energy on a firm basis from a point of receipt to a point of delivery. In addition, Network Integration Transmission Service delivers power to load within BPA's balancing authority area and is a significant component of transmission revenues. Revenue from ancillary services and the Southern Intertie also comprise a significant portion of transmission revenues. Ancillary services ensure transmission grid reliability and include items such as scheduling, dispatch, balancing reserves and other services. The Southern Intertie is a system of transmission lines used primarily to transmit power between the Pacific Northwest and California. The majority of intertie revenue is from long-term contracts exceeding one year in duration. Transmission customers include entities that buy and sell non-federal power in the region, in-region purchasers of federal power, generators, power marketers and utilities that seek to transmit power into, out of or through the region.

"Other" revenues source primarily from the sales of power and other services or items by Reclamation and USACE. In particular, Reclamation sells power to certain Pacific Northwest irrigation districts. Other revenues also include reimbursable revenues associated with work performed for BPA customers. Reimbursable revenues are offset by an equivalent amount of reimbursable expenses.

Also included within other revenues are the following types of revenue not with customers: leasing fees that BPA receives as the lessor of certain fiber optic cables and other assets; revenue from deferred project revenue funded in advance, which is recognized over the life of the corresponding transmission assets once placed in service and reduces the associated liability; and realized gains on financial futures contracts. (See Note 11, Deferred Credits and Other for further information on deferred project revenue funded in advance.)

U.S. TREASURY CREDITS

U.S. Treasury credits represent BPA's recovery of certain nonpower-related costs from the U.S. Treasury in accordance with certain laws. The primary U.S. Treasury credit is the 4(h)(10)(C) credit provided for in the Northwest Power Act. This Act requires BPA to recover the nonpower portion of expenditures—set at 22.3%—that BPA makes for fish and wildlife protection, mitigation and enhancement. Through Section 4(h)(10)(C), the Northwest Power Act ensures that the costs of mitigating these impacts are allocated between the power-related and other purposes of the federal hydroelectric projects of the FCRPS. Power-related costs are recovered in BPA's rates. U.S. Treasury credits are reported as a component of Operating revenues in the Combined Statements of Revenues and Expenses.

As part of its annual payment to the U.S. Treasury, BPA applies the U.S. Treasury credits earned each fiscal year against various categories of payment obligations. For example, BPA may apply U.S. Treasury credits against interest expense or liabilities such as borrowings from U.S. Treasury and federal appropriations.

CONTRACT BALANCES

As of Sept. 30 — millions of dollars	2024	2023
Receivable assets		
Accounts receivable, net of allowance	$ 95.4	$ 84.7
Accrued unbilled revenues	348.2	282.7
Contract liabilities		
Customer prepaid power purchases	$ 111.7	$ 139.2
Third AC Intertie capacity agreements	80.2	82.6
Unearned revenue from customer deposits	73.9	66.0
Revenue recognized during the fiscal year from amounts included in contract liabilities at the beginning of the year	$ 98.2	$ 94.6

Accounts receivable and accrued unbilled revenues source primarily from contracts with customers.

Contract liabilities represent an entity's unsatisfied performance obligation to transfer goods or services to a customer from which the entity has received consideration. The contract liability amounts in the table above show expected future revenues to be recorded as power is delivered (for customer prepaid power purchases), over the estimated life of transmission assets placed in service (for Third AC Intertie capacity agreements), or as expenditures are incurred (for unearned revenue from customer deposits). These contract liabilities have no variable consideration and require little or no significant judgment in revenue recognition. The average contract term varies by customer and type and may span several years. (See Note 8, Debt and Appropriations, for further information on customer prepaid power purchases, and Note 11, Deferred Credits and Other, for further information on Third AC Intertie capacity agreements and unearned revenue from customer deposits.)

3. Utility Plant and Nonfederal Generation

As of Sept. 30 — millions of dollars	2024	2023	2024 Estimated average service lives
Completed plant			
Federal system hydro generation assets	$ 10,507.4	$ 10,337.3	75 years
Transmission assets	11,624.3	11,230.0	51 years
Other assets	104.2	107.4	8 years
Completed plant	$ 22,235.9	$ 21,674.7	
Accumulated depreciation			
Federal system hydro generation assets	$ (4,266.0)	$ (4,139.2)	
Transmission assets	(4,284.7)	(4,126.6)	
Other assets	(54.2)	(50.2)	
Accumulated depreciation	$ (8,604.9)	$ (8,316.0)	
Construction work in progress			
Federal system hydro generation assets	$ 693.5	$ 588.5	
Transmission assets	1,507.8	1,118.7	
Other assets	35.1	25.9	
Construction work in progress	$ 2,236.4	$ 1,733.1	
Nonfederal generation	$ 3,410.0	$ 3,380.0	
Net utility plant and nonfederal generation	$ 19,277.4	$ 18,471.8	

Allowance for funds used during construction

Fiscal year	2024	2023	2022
BPA rate	3.3%	3.0%	2.4%
Appropriated rate	5.5%	3.6%	0.1%

Amounts accrued in Accounts payable and other on the Combined Balance Sheets for Construction work in progress assets were approximately $168 million, $122 million, and $93 million as of Sept. 30, 2024, 2023, and 2022, respectively.

4. Leases

An arrangement contains a lease if a lessee has the right to control an identified asset for a period of time in exchange for consideration. At contract inception, management determines whether an arrangement contains a lease and lease classification, if applicable. At the lease commencement date, lease right-of-use (ROU) assets and lease liabilities are recorded based upon the present value of lease payments over the lease term, including initial direct costs, if any. If a contract provides an implicit rate, it is used to determine the present value of future lease payments. If a contract does not provide an implicit rate, management uses the incremental borrowing rate available at lease commencement. Operating lease ROU assets include any lease payments made at or before the commencement date and exclude lease incentives.

Certain lease arrangements contain renewal or early termination options. If management is reasonably certain to exercise these options, they are included in the calculation of the ROU asset and lease liability by incorporating the option into the lease term. Certain renewal options include an adjustment to future lease cost based upon various factors, such as pre-determined percentage increases, the Consumer Price Index, or other methods. Management has also elected to account for arrangements with lease and non-lease components as a single lease component.

Operating leases are primarily for office spaces and leased vehicles. Operating lease terms range from 1 to 34 years. Finance leases are primarily for transmission lines and equipment. Finance lease terms range from less than one year to 63 years. There were no material lessor arrangements as of Sept. 30, 2024, and 2023.

The following table provides supplemental balance sheet information related to leases:

As of Sept. 30 — millions of dollars	Financial Statement Line Item	2024	2023
Operating leases			
ROU assets	Deferred charges and other	$ 101.3	$ 91.4
Short-term lease liability	Accounts payable and other	14.6	16.4
Long-term lease liability	Deferred credits and other	86.8	75.0
Finance leases			
ROU assets	Completed plant	$ 97.7	$ 99.1
Short-term lease liability	Nonfederal debt	5.8	4.9
Long-term lease liability	Nonfederal debt	97.5	99.5

The following table provides supplemental expense information related to total lease costs:

Years ended Sept. 30 — millions of dollars	Financial Statement Line Item	2024	2023	2022
Operating lease cost [1]	Operations and maintenance	$ 18.8	$ 18.7	$ 18.6
Finance lease cost:				
Amortization of ROU assets	Depreciation, amortization and accretion	6.0	5.2	4.5
Interest on lease liabilities	Interest expense	5.2	5.1	5.1
Total lease costs		$ 30.0	$ 29.0	$ 28.2

[1] Includes variable lease costs, which were immaterial for the fiscal years ended Sept. 30, 2024, 2023 and 2022.

	Weighted-average remaining lease term	Weighted-average discount rate
Operating leases	7.0 years	3.2%
Finance leases	46.1 years	5.1%

The following table provides supplemental cash flow information related to leases:

Years ended Sept. 30 - millions of dollars	2024	2023	2022
Cash paid for amounts included in the measurement of lease liabilities			
Operating cash outflows:			
Operating lease payments	$ 18.8	$ 18.7	$ 18.6
Interest on finance leases	5.2	5.1	5.1
Financing cash outflows:			
Principal payments on finance lease	5.7	4.4	3.8
Right-of-use assets obtained in exchange for new lease obligations			
Operating leases	26.5	9.3	3.0
Finance leases	4.5	8.2	7.0

The following table provides maturities of operating lease liabilities:

As of Sept. 30 - millions of dollars	
2025	$ 17.6
2026	18.3
2027	17.6
2028	14.6
2029	14.3
2030 and thereafter	31.7
Total undiscounted lease liabilities	$ 114.1
Less: Amounts representing interest	12.7
Total lease liabilities	$ 101.4

See Note 8, Debt and Appropriations, for finance lease maturity analysis.

5. Effects of Regulation

Regulatory assets include the following items:

REGULATORY ASSETS

As of Sept. 30 — millions of dollars	2024	2023
Terminated nuclear facilities	$ 1,355.0	$ 1,425.4
IOU exchange benefits	1,062.8	1,299.2
Columbia River Fish Mitigation	725.4	745.2
Phase 2 Implementation Plan (P2IP) Settlement Agreement	252.8	252.8
Irrigation assistance	227.6	—
Fish and wildlife measures	206.8	213.5
Resilient Columbia Basin Agreement - Six Sovereigns	111.2	—
Trojan decommissioning and site restoration	94.6	92.9
Spacer damper replacement program	43.1	46.0
Conservation measures	26.0	48.3
Legal claims and settlements	22.0	22.0
Federal Employees' Compensation Act	21.0	17.8
Other	3.1	3.6
Derivative instruments	1.7	1.8
Terminated hydro facilities	0.3	2.2
Terminated I-5 Corridor Reinforcement Project	—	26.0
Decommissioning and site restoration	—	75.7
Total	$ 4,153.4	$ 4,272.4

"**Terminated nuclear facilities**" consist of amounts to be recovered in future rates to satisfy the nonfederal debt for Energy Northwest Projects 1 and 3. These assets are amortized to depreciation, amortization and accretion through 2043, as established in the rate case.

"**IOU exchange benefits**" reflect amounts to be recovered in rates through 2028 for the IOU exchange benefits liability incurred as part of the 2012 REP Settlement Agreement. These amounts are amortized to operations and maintenance expense. (See Note 10, Residential Exchange Program.)

"**Columbia River Fish Mitigation**" is the cost of research and development for fish bypass facilities funded through appropriations since 1989 in accordance with the Energy and Water Development Appropriations Act of 1989, Public Law 100-371. Through fiscal year 2021, these costs were recovered in rates over 75 years and amortized to depreciation, amortization and accretion expense. Beginning in fiscal year 2022, these costs are no longer deferred and are instead recorded as operations and maintenance expense when incurred. In addition, beginning in fiscal year 2022 the amortization period for remaining deferred amounts has changed from 75 years to 50 years as stated in the BP-22 rate case.

"**Phase 2 Implementation Plan (P2IP) Settlement Agreement**" represents the deferral of expenses related to the P2IP settlement agreement signed in September 2023. BPA expects that these costs will be recovered through future rates. The amortization period and expense location on the Combined Statements of Revenues and Expenses will be determined prior to the BP-26 rate proposal. (For further information on the P2IP transaction, see Note 11, Deferred Credits and Other.)

"**Irrigation assistance**" reflects the amount to be recovered in future rates through 2045 in connection with the annual irrigation assistance payment made to the U.S. Treasury. Amortization of these costs will be recorded as non-operating expenses under Irrigation assistance on the Combined Statements of Revenues and Expenses in the year of payment. (For further information on Irrigation assistance, see Note 11, Deferred Credits and Other and Note 14, Commitments and Contingencies.)

"**Fish and wildlife measures**" consist of deferred fish and wildlife project expenses to be recovered in future rates. These costs are amortized to depreciation, amortization and accretion expense over a period of 15 years.

“**Resilient Columbia Basin Agreement – Six Sovereigns**” represents the deferral of expenses related to the settlement agreement signed in December 2023 between BPA and certain state and tribal partners, collectively known as the Six Sovereigns. BPA expects that these costs will be recovered through future rates. The amortization period and expense location on the Combined Statements of Revenues and Expenses will be determined prior to the BP-26 rate proposal. (For further information on this transaction, see Note 11, Deferred Credits and Other.)

“**Trojan decommissioning and site restoration**” reflects the amount to be recovered in future rates for funding the asset retirement obligation (ARO) liability related to the former Trojan nuclear facility through 2059. This amount equals the associated liability. (See Note 6, Asset Retirement Obligations.)

“**Spacer damper replacement program**” consists of costs to replace deteriorated spacer dampers on certain transmission lines and are recovered in future rates under the Spacer Damper Replacement Program. These costs are amortized to depreciation, amortization and accretion expense over a period of 25 or 30 years.

“**Conservation measures**” consist of the costs of deferred energy conservation measures to be recovered in future rates. These costs are amortized to depreciation, amortization and accretion expense over periods of 12 or 20 years. BPA deferred certain costs of energy conservation measures through fiscal year 2015 and, beginning with fiscal year 2016, began recording such costs as operations and maintenance expense when incurred.

“**Legal claims and settlements**” reflect amounts to be recovered in future rates to satisfy accrued liabilities related to legal claims and settlements. These costs will be recovered and amortized to operations and maintenance expense over a period to be established during future rate cases.

“**Federal Employees’ Compensation Act**” reflects the actuarial estimated amount of future payments for current recipients of BPA’s worker compensation benefits. This amount equals the associated liability, and related expenses are recorded to operations and maintenance expense as payments are made. (See Note 11, Deferred Credits and Other.)

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

“**Terminated hydro facilities”** consist of the amounts to be recovered in future rates to satisfy nonfederal debt for the Northern Wasco Hydro Project, for which BPA ceased its participation as recipient of the project’s electric power. These assets are amortized to depreciation, amortization and accretion through 2025, as established in the rate case. (See Note 8, Debt and Appropriations.)

“Terminated I-5 Corridor Reinforcement Project” consists of the costs to be recovered in future rates for preliminary construction and related activities for the former I-5 Corridor Reinforcement Project. These costs were amortized to depreciation, amortization and accretion expense through 2024, as established in the rate case.

“**Decommissioning and site restoration**” represents unrealized losses in the nonfederal nuclear decommissioning trust assets for the Columbia Generating Station. (See Note 6, Asset Retirement Obligations.)

Regulatory liabilities include the following items:

REGULATORY LIABILITIES

As of Sept. 30 — millions of dollars	2024	2023
Capitalization adjustment	$ 758.0	$ 822.9
Accumulated plant removal costs	709.2	666.2
Decommissioning and site restoration	36.4	2.6
Derivative instruments	18.8	51.5
Total	$ 1,522.4	$ 1,543.2

“**Capitalization adjustment**” is the difference between the outstanding balance of federal appropriations, plus $100 million, before and after refinancing under the BPA Refinancing Section of the Omnibus Consolidated Rescissions and Appropriations Act of 1996, 16 U.S.C. 838(l). Consistent with treatment in BPA’s power and transmission rate cases, this adjustment is amortized over a 40-year period through fiscal year 2036. Amortization of the capitalization adjustment as a reduction to interest expense was $64.9 million each year for fiscal years 2024, 2023 and 2022.

"**Accumulated plant removal costs**" represent a liability for amounts previously collected through rates as part of depreciation expense. The liability increases as depreciation expense is incurred and is reduced as actual costs of removal, net of proceeds, are incurred. (See Note 1, Summary of Significant Accounting Policies.)

"**Decommissioning and site restoration**" represents unrealized gains in the nonfederal nuclear decommissioning trust assets for the Columbia Generating Station. (See Note 6, Asset Retirement Obligations.)

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

6. Asset Retirement Obligations

Asset retirement obligations include the following items:

As of Sept. 30 — millions of dollars		2024		2023
CGS decommissioning and site restoration	$	1,020.7	$	921.8
Trojan decommissioning		94.6		92.9
Energy Northwest Projects 1 and 4 site restoration		2.9		0.4
Total	$	1,118.2	$	1,015.1

AROs represent the legal obligations associated with the future retirement of certain tangible, long-lived assets. FCRPS AROs are recognized based on the estimated fair value of the dismantlement and restoration costs, primarily associated with the retirement of the Columbia Generating Station. BPA also has AROs for a 30% share of the former Trojan nuclear power plant decommissioning activities and for certain Energy Northwest-related site restoration activities. ARO liabilities are adjusted for any revisions, expenditures and the passage of time.

As of Sept. 30 — millions of dollars		2024		2023		2022
Beginning Balance	$	1,015.1	$	964.3	$	929.2
Activities:						
Accretion		42.8		40.2		38.6
Expenditures		(5.6)		(5.5)		(6.1)
Revisions		65.9		16.1		2.6
Ending Balance	$	1,118.2	$	1,015.1	$	964.3

As a result of a 2024 site-specific decommissioning study for CGS, BPA management increased the estimate for the CGS ARO liability by $59.1 million. This change in estimate was largely driven by higher labor costs, increases in low-level radioactive waste disposal rates and increases in spent fuel cask procurement and management costs. Actual decommissioning costs may vary from this estimate because of various factors including future decommissioning dates, requirements, costs and technology. A $59.1 million increase to the Nonfederal generation asset on the Combined Balance Sheets offset the increased ARO liability.

Based on agreements in place, BPA directly funds Eugene Water and Electric Board's 30% share of the former Trojan nuclear power plant decommissioning activities that consist of long-term operation and decommissioning of the Independent Spent Fuel Storage Installation (ISFSI). BPA funds these costs through current rates, with the expenses included in Operations and maintenance in the Combined Statements of Revenues and Expenses. Trojan decommissioning primarily relates to the storage of spent nuclear fuel through 2059 at the former nuclear plant site. Decommissioning of the ISFSI and final site restoration activities is not expected to occur before 2059, which is the year the Nuclear Regulatory Commission (NRC) extended the fuel storage license through. In fiscal year 2024, BPA management revised the estimate for the Trojan ARO liability by $3.1 million. This change in estimate was driven by the aging management program, headcount and frequency of cask inspections. In fiscal year 2023, BPA management revised the estimate for the Trojan ARO liability by $14.9 million. This change in estimate was driven by increases in expected annual ISFSI operation costs primarily due to additional personnel and construction-related expenses. A $14.9 million increase to Regulatory assets on the Combined Balance Sheets offset the increased ARO liability in fiscal year 2023.

Based on a prior settlement agreement with the DOE, BPA receives an annual reimbursement for certain costs related to monitoring the spent nuclear fuel. BPA reduces operations and maintenance expense when it receives the reimbursement, which was $2.7 million, $1.8 million, and $1.5 million in fiscal years 2024, 2023, and 2022, respectively.

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

NONFEDERAL NUCLEAR DECOMMISSIONING TRUSTS

As of Sept. 30 — millions of dollars	2024		2023	
	Amortized cost	Fair value	Amortized cost	Fair value
Equity securities	$ 456.5	516.4	$ 442.4	$ 396.1
Debt securities	113.6	89.9	95.9	66.4
Cash and cash equivalents	17.2	17.2	17.0	17.0
Total	$ 587.3	623.5	$ 555.3	$ 479.5

These assets are trust fund account balances, primarily for CGS decommissioning and site restoration costs, but also for site restoration at Energy Northwest Projects 1 and 4, which terminated prior to completion. The fair value of the trust fund balances for CGS decommissioning and site restoration costs as of Sept. 30, 2024, and 2023 were $606.3 million and $462.5 million, respectively. The investment securities in the CGS decommissioning and site restoration trust fund accounts comprise both equity and debt securities and are recorded at fair value in accordance with applicable accounting guidance. Equity securities include both domestic and international index mutual funds. Debt securities are classified as available-for-sale and include bond mutual funds that hold inflation-protected securities. The trust fund balances for the site restoration at Energy Northwest Projects 1 and 4 were $17.2 million and $17 million, respectively. The site restoration fund for Energy Northwest Projects 1 and 4 is invested in a money market fund that is considered cash and cash equivalents.

External trust fund accounts for decommissioning and site restoration costs for CGS are funded monthly, with these contributions recorded as an increase to the trust fund asset. The CGS decommissioning trust fund account was established to provide for decommissioning at the end of the project's operations in accordance with NRC requirements. The NRC requires that this period be no longer than 60 years from the time the plant ceases operations. Decommissioning funding requirements for CGS are based on a 2024 site-specific decommissioning study for CGS and the current license termination date, which is in December 2043. The CGS trust fund accounts are funded and managed by BPA in accordance with NRC requirements and site certification agreements.

Unrealized gains and losses are recorded to a regulatory liability or regulatory asset, respectively. Realized gains and losses for CGS are recorded to Other, net in the Combined Statements of Revenues and Expenses and were considered when establishing rates for fiscal years 2022 through 2024. Realized gains reported for fiscal years 2024, 2023 and 2022 were $2.5 million, $0.1 million, and $2.9 million, respectively.

Contribution payments to the CGS trust fund accounts for fiscal years 2024, 2023 and 2022 were $15.1 million, $4.9 million and $4.7 million, respectively. Based on current estimates, BPA and Energy Northwest have no obligation to make further payments into the site restoration fund for Energy Northwest Projects 1 and 4.

7. Deferred Charges and Other

Deferred Charges and Other include the following items:

As of Sept. 30 — millions of dollars	2024		2023	
Operating leases	$	101.3	$	91.4
Lease-Purchase trust funds		22.6		35.7
Derivative instruments		18.8		51.5
Transmission line-related receivables		10.4		10.4
Spectrum Relocation Fund		8.2		8.2
Cloud computing arrangements		5.5		6.2
Other		2.8		3.9
Water storage agreements		—		14.7
Total	$	169.6	$	222.0

"**Operating leases**" represent right-of-use assets that are amortized to operations and maintenance expense over the term of the related leases. (See Note 4, Leases.)

"**Lease-Purchase trust funds**" are investments held in separate trust accounts outside the Bonneville Fund for the construction and administration of leased transmission assets, the use of which BPA has acquired under lease-purchase agreements. The amounts held in trust are also used in part for debt service payments during the construction period and include an investment fund mainly for future principal and interest debt service payments. (See Note 8, Debt and Appropriations.) Interest income and realized and unrealized gains or losses on amounts held in trust for construction are recorded as AFUDC. Interest income and gains and losses on other trust balances are recorded as either income or expense in the period when earned. At the time of debt extinguishment, unspent trust funds under a particular transaction are used to repay the related lease-purchase debt and associated debt extinguishment costs for that transaction.

The Lease-Purchase trust funds are primarily comprised of held-to-maturity fixed-income investments and cash and cash equivalents.

Investments classified as held-to-maturity were $19 million and $19.1 million as of Sept. 30, 2024, and 2023, and are recorded at amortized cost. The fair value of held-to-maturity investments exceeded amortized cost by approximately $2 million and $1 million as of Sept. 30, 2024, and 2023, respectively. Unrealized gains comprise the difference between amortized cost and fair value for both years. Held-to-maturity investments as of Sept. 30, 2024, mature in November 2030.

As of Sept. 30, 2024, and 2023, trust balances also included cash and cash equivalents of $3.6 million and $14 million, respectively.

Investments classified as available-for-sale were $0 and $2.6 million at Sept. 30, 2024, and 2023, respectively. These investments were held for construction purposes and were stated at fair value based on quoted market prices. The fair value of these investments approximated amortized cost, with immaterial unrealized and realized gains or losses recorded during fiscal years 2023, and 2022. (See Note 13, Fair Value Measurements.)

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

"**Transmission line-related receivables**" represent the receivable assets recorded in relation to the March 2023 Boardman to Hemingway with Transfer Service transaction, in which BPA transferred its 24.24% permitting interest share in the proposed Boardman to Hemingway transmission line to Idaho Power Company (IPC). Taking into account the time value of money and project risks, the permitting interest transfer resulted in a $3.4 million financial asset and a corresponding non-cash gain recorded to Other, net related to the sale. Additionally, BPA paid IPC a $10 million security payment which, once adjusted for the time value of money, resulted in a $7 million deferred asset increase, and a $3 million loss recorded to Other, net.

BPA expects to receive approximately $31 million, plus interest, from IPC over 10 years beginning 10 years after IPC builds and energizes the B2H transmission line and also reaches service thresholds as defined in the aforementioned March 2023 contracts. Additionally, upon energization BPA expects to recover the $10 million security payment from IPC.

“**Spectrum Relocation Fund**” was created to reimburse certain federal agencies such as BPA for the costs of replacing radio communication equipment displaced as a result of radio band frequencies no longer available to the affected federal agencies. These amounts previously received from the U.S. Treasury are held as restricted cash in the Bonneville Fund for the sole purpose of constructing replacement assets. These amounts are the only source of restricted cash reported on the Combined Statements of Cash Flows.

“**Cloud computing arrangements**” represent the capitalized implementation costs incurred in a cloud computing arrangement that is a service contract. These costs are amortized to operations and maintenance expense over the terms of the respective contracts once placed in service.

“**Water storage agreements**” represent amounts owed to BPA by BC Hydro, an electric utility owned by the Province of British Columbia. Yearly fluctuations in water levels, river operations and storage plans, particularly at certain dams in and near Canada, affect the amounts owed to or from BC Hydro. The final annual amount is invoiced based on August 31 ending balances.

8. Debt and Appropriations

As of Sept. 30 — millions of dollars		2024			2023		
	Terms		Carrying Value	Weighted-Average Interest Rate		Carrying Value	Weighted-Average Interest Rate
Nonfederal debt							
Nonfederal generation:							
Columbia Generating Station	0.9 – 5.0% through 2042	$	3,434.4	4.4%	$	3,381.9	4.5%
Cowlitz Falls Hydro Project	4.0 – 5.3% through 2032		47.3	5.1		52.0	5.1
Terminated nonfederal generation:							
Nuclear Project 1	0.9 – 5.0% through 2042		829.0	4.8		837.5	4.8
Nuclear Project 3	2.9 – 5.0% through 2042		967.4	4.8		970.6	4.9
Northern Wasco Hydro Project	5.0% through 2024		1.9	5.0		3.6	5.0
Lease-Purchase Program:							
Lease-purchase liability	2.3 – 4.9% through 2046		1,671.7	2.9		1,766.8	2.8
NIFC debt	5.4% through 2034		119.1	5.4		119.1	5.4
Finance lease liability	1.3 – 6.9% through 2087		103.3	5.1		104.4	4.9
Other financial liability	3.4% through 2043		15.4	3.4		16.0	3.4
Customer prepaid power purchases	4.3 – 4.6% through 2028		111.7	4.5		139.2	4.5
Total Nonfederal debt		$	7,301.2	4.2%	$	7,391.1	4.2%
Federal debt and appropriations							
Borrowings from U.S. Treasury	0.4 – 5.9% through 2053	$	5,960.7	3.4%	$	5,783.8	3.4%
Federal appropriations	1.4 – 4.4% through 2074		1,110.7	3.2		1,123.9	3.2
Federal appropriations (not scheduled for repayment)			586.4	n/a		473.7	n/a
Total Federal debt and appropriations		$	7,657.8	3.3%	$	7,381.4	3.4%
Total debt and appropriations		$	14,959.0	3.8%	$	14,772.5	3.8%

NONFEDERAL DEBT

Nonfederal generation and Terminated nonfederal generation

As described in Note 1, Summary of Significant Accounting Policies, Nonfederal generation section, BPA is party to long-term contracts for BPA to acquire all of the generating capability of Energy Northwest’s Columbia Generating Station and, through June 2032, all of Lewis County PUD’s Cowlitz Falls Hydroelectric Project. Under certain agreements, BPA also has financial responsibility for meeting all costs of Energy Northwest’s Projects 1 and 3, including debt service costs of bonds and other financial instruments issued for the projects, even though these projects have been terminated. BPA is also required by a “Settlement and Termination Agreement” between BPA and Northern Wasco PUD to pay amounts equal to annual debt service on certain bonds of the Northern Wasco Hydro Project. Under the Settlement and Termination Agreement, BPA ceased its participation in this project.

Cowlitz Falls Hydroelectric Project debt of $47.3 million is callable, in whole or in part, at Lewis County PUD’s option with the approval of BPA, at 100% of the principal amount plus accrued interest.

BPA recognizes certain expenses for these nonfederal generation and terminated nonfederal generation projects based on annual total project cash funding requirements, which include interest expense and operating and maintenance expense. BPA recognized operating and maintenance expense for these projects of $331.5 million, $327 million and $287.4 million in fiscal years 2024, 2023 and 2022, respectively, which is included in Operations and maintenance in the Combined Statements of Revenues and Expenses. On the Combined Balance Sheets, related assets for CGS and the Cowlitz Falls Hydroelectric Project are included in Nonfederal generation. Related assets for terminated nonfederal generation are included in Regulatory assets. (See Note 5, Effects of Regulation.)

During fiscal year 2024, BPA recorded gains of $2 million when certain Energy Northwest debt was extinguished via the issuance of long-term debt. BPA recorded no similar gains or losses during fiscal year 2023 but recorded gains of $2.2 million during fiscal year 2022.

Energy Northwest debt of $3.12 billion is callable, in whole or in part, at Energy Northwest’s option with the approval of BPA, on call dates between July 2025 and July 2034 at 100% of the principal amount.

Lease-Purchase Program

Under the Lease-Purchase Program, BPA has incurred financial liabilities for lease-purchase transactions with certain third-party entities. These transactions are primarily with the Port of Morrow, a port district located in Morrow County, Oregon, and the Idaho Energy Resources Authority (IERA), an independent public instrumentality of the State of Idaho, for transmission facilities, including lines, substations and general plant assets. These financial liabilities are paid from the rental payments made by BPA. The facilities are not security for the payment of these obligations. The lease-purchase agreements contain provisions that allow BPA to purchase the related assets at any time during each lease term for a bargain purchase price plus the value of the related outstanding debt instrument. During fiscal year 2024, BPA recorded a $2.1 million gain when certain lease-purchase liabilities were extinguished via the issuance of long-term debt.

Under the Lease-Purchase Program, BPA consolidates one special purpose corporation, Northwest Infrastructure Financing Corporation, or NIFC. (See Note 9, Variable Interest Entities.) As of Sept. 30, 2024, and 2023, the NIFC had $119.6 million of bonds outstanding, including debt issuance costs. The rental payments from BPA are pledged to the payment of the debt, but the facilities do not secure the debt. The NIFC bonds are reported as NIFC debt and are subject to redemption by NIFC, in whole or in part, at any date, at the higher of the principal amount of the bonds or the present value of the bonds discounted using the U.S. Treasury rate plus a premium of 12.5 basis points.

On the Combined Balance Sheets, the Lease-Purchase liability and NIFC debt are included in Nonfederal debt. The related assets are included in Utility plant and in Deferred charges and other for unspent funds held in trust accounts outside the Bonneville Fund.

Finance lease liability

Included among this liability are finance lease agreements for transmission lines and equipment. The related assets are recorded as completed plant. For additional information regarding finance leases, see Note 4, Leases.

Other financial liability

This agreement is with a transmission customer. BPA is deemed the accounting owner of the assets, which are included in Utility plant on the Combined Balance Sheets. The agreement contains provisions that allow BPA to purchase the related assets at any time during the contract term, with ownership transferring to BPA at the end of the term.

Customer prepaid power purchases

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

In March 2013, BPA received $340 million representing $474.3 million in scheduled credits for blocks purchased by customers. BPA accounts for the prepayment proceeds as a financing transaction and reports the value of the obligations associated with the fixed credits as a prepayment liability. Interest expense is recognized using a weighted-average effective interest rate of 4.5%. The prepaid liability is reduced and the credits are applied as power is delivered through fiscal year 2028.

FEDERAL DEBT AND APPROPRIATIONS

Borrowings from U.S. Treasury

BPA is authorized by Congress to issue and sell bonds to the U.S. Treasury and to have outstanding at any time up to $13.70 billion aggregate principal amount of bonds. Beginning in fiscal year 2028, an additional $4.00 billion of U.S. Treasury borrowing authority will be available. Of the $13.70 billion in borrowing authority currently available, $1.25 billion is available for electric power conservation and renewable resources, including capital investment at the FCRPS hydroelectric facilities owned by the USACE and Reclamation, and $12.45 billion is available for BPA's transmission capital program and to implement BPA's authorities under the Northwest Power Act. Of the total U.S. Treasury borrowing authority available at any one time ($13.70 billion through fiscal year 2027 and $17.70 billion beginning in fiscal year 2028), $750 million can be issued to finance Northwest Power Act-related expenses. The interest on BPA's outstanding bonds is set at rates comparable to rates on debt issued by other comparable federal government institutions at the time of issuance. Bonds can be issued with call options.

As of Sept. 30, 2024, and 2023, no bonds outstanding were related to Northwest Power Act expenses.

As of Sept. 30, 2024, $392.1 million of variable-rate bonds are callable by BPA at par value on their interest repricing dates, which occurs every three or six months. The remaining $5.57 billion of bonds 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 bonds are called. As of Sept. 30, 2023, $495.2 million of variable-rate bonds were outstanding.

In fiscal year 2024, BPA called $274.1 million of bonds it had previously issued to the U.S. Treasury. As a result, BPA recognized a net loss of $0.1 million to Other, net in the Combined Statements of Revenues and Expenses. Additionally, in fiscal year 2023, BPA called $322.9 million of bonds it had previously issued to the U.S. Treasury, and recognized a related net gain of $5 million to Other, net in the Combined Statements of Revenues and Expenses. BPA recorded no such gains or losses during fiscal year 2022.

Federal appropriations

Federal appropriations reflect the responsibility that BPA has to repay the U.S. Treasury for congressionally appropriated amounts in the FCRPS. Federal appropriations repayment obligations consist of the remaining unpaid power portion of USACE and Reclamation capital investments funded through congressional appropriations. These include appropriations for the Columbia River Fish Mitigation program as allocated to the power purpose of the USACE's FCRPS hydroelectric projects. BPA's repayment obligation begins when capital investments are completed and placed into service, unless directed otherwise by specific legislation.

BPA is obligated to establish rates to repay appropriations for federal generation and transmission plant investments within a specified repayment period, which is the reasonably expected service life of the facilities, not to exceed 50 years. Federal appropriations may be repaid early without penalty at their par value (i.e., carrying value for federal appropriations) as part of BPA's payment to the U.S. Treasury. BPA repaid appropriations earlier than their due dates in fiscal years 2024 and 2023. BPA establishes schedules for the repayment of federal appropriations when it establishes its power and transmission rates. These schedules can change depending on whether appropriations have been prepaid or deferred. Interest on appropriated amounts begins accruing when the related assets are placed into service, unless repayment obligation is deferred by specific legislation.

As of Sept. 30 — millions of dollars	Maturing Nonfederal debt excluding finance leases	Future minimum lease payments under finance leases	Borrowings from U.S. Treasury	Federal appropriations	Total
2025	$ 572.7	$ 10.9	$ 114.0	$ —	$ 697.6
2026	581.8	8.9	131.0	—	721.7
2027	528.9	7.6	181.0	—	717.5
2028	673.2	7.3	309.8	—	990.3
2029	134.2	7.1	306.0	—	447.3
2030 and thereafter	5,048.9	164.0	4,918.9	1,697.1	11,828.9
Total	$ 7,539.7	$ 205.8	$ 5,960.7	$ 1,697.1	$ 15,403.3
Less: Executory costs	2.7	—	—	—	2.7
Less: Amount representing interest	681.8	102.5	—	—	784.3
Less: Unamortized debt issuance cost	20.3	—	—	—	20.3
Plus: Unamortized premiums	363.0	—	—	—	363.0
Present value of debt	7,197.9	103.3	5,960.7	1,697.1	14,959.0
Less: Current portion	516.1	5.8	114.0	—	635.9
Long-term debt	$ 6,681.8	$ 97.5	$ 5,846.7	$ 1,697.1	$ 14,323.1

FAIR VALUE OF DEBT AND APPROPRIATIONS

See Note 13, Fair Value Measurements, for a comparison of carrying value to fair value for debt. Due to the current par value call provision on BPA's federal appropriations, the fair value of BPA's federal appropriations is equal to the carrying value. This call provision allows BPA to prepay appropriations repayment obligations without premiums or a mark-to-market adjustment.

9. Variable Interest Entities

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

Management reviews executed lease-purchase agreements with nonfederal entities for VIE accounting impacts. BPA has determined that NIFC is a VIE and that BPA is the primary beneficiary of NIFC. As such, this entity is consolidated. The key factors in this determination are BPA's ability to take contractual actions that significantly impact the economic, commercial and operating activities of NIFC and BPA's obligation to absorb losses that could be significant to NIFC. Additionally, BPA's lease-purchase agreement with NIFC obligates BPA to absorb the operational and commercial risks, and thus potentially significant benefits or losses associated with the underlying transmission facilities. BPA also has exclusive use and control of the facilities during the lease period and has indemnified NIFC for all construction and operating risks associated with its transmission facilities.

Amounts related to NIFC include Lease-Purchase trust funds and other assets of $20.6 million and Nonfederal debt of $119.1 million as of Sept. 30, 2024, and 2023. BPA has also entered into lease-purchase agreements with Port of Morrow and IERA, which are nonfederal entities. These entities are governmental and, in accordance with VIE accounting guidance, are therefore not consolidated into the FCRPS financial statements. (See Note 8, Debt and Appropriations.)

BPA has entered into power purchase agreements with wind farm-related VIEs, which, because of their pricing arrangements, provide that BPA absorb commodity price risk from the perspective of the counterparty entities. However, BPA management has concluded that in no instance does BPA have the power to control the most significant operating and maintenance activities of these entities. Therefore, BPA is not the primary beneficiary and does not consolidate these entities. Additionally, 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. Thus, BPA has no exposure to loss on contracts with these VIEs. Expenses related to VIEs for which BPA is not the primary beneficiary were $7.8 million, $9.5 million and $16.5 million in fiscal years 2024, 2023 and 2022, respectively. These expenses were recorded to operations and maintenance as BPA management considers the related purchases to be part of the FCRPS resource pool.

10. Residential Exchange Program

BACKGROUND

In 1981 and as provided in the Northwest Power Act, BPA began to implement the Residential Exchange Program (REP) through various contracts with eligible regional utility customers. BPA's implementation of the REP has been the subject of various litigations and settlement agreements.

REP SCHEDULED AMOUNTS

As of Sept. 30 — millions of dollars		
2025	$	273.6
2026		286.1
2027		286.1
2028		286.1
Subtotal of annual payments		1,131.9
Less: Discount for present value		69.1
IOU exchange benefits	$	1,062.8

2012 RESIDENTIAL EXCHANGE PROGRAM SETTLEMENT AGREEMENT

Beginning in April 2010, over 50 litigants and other regional parties entered into mediation to resolve numerous disputes over the REP. In fiscal year 2011 the parties reached a final settlement agreement – the 2012 Residential Exchange Program Settlement Agreement (2012 REP Settlement Agreement). As a result of the settlement, BPA recorded an associated long-term IOU exchange benefits liability and corresponding regulatory asset of $3.07 billion. Under the 2012 REP Settlement Agreement, the IOUs' REP benefits were determined for fiscal years 2012 - 2028 (also referred to herein as Scheduled Amounts). The Scheduled Amounts started at $182.1 million for fiscal year 2012 and increase over time to $286.1 million for fiscal year 2028. As provided in the 2012 REP Settlement Agreement, the Scheduled Amounts are established for each IOU based on the IOU's average system cost, its residential exchange load and BPA's applicable Priority Firm Exchange rate. The Scheduled Amounts total $4.07 billion over the 17-year period through fiscal year 2028, with remaining Scheduled Amounts as of Sept. 30, 2024, totaling $1.13 billion. Amounts recorded of $1.06 billion at Sept. 30, 2024, represent the present value of future cash outflows for these IOU exchange benefits.

11. Deferred Credits and Other

Deferred Credits and Other include the following items:

As of Sept. 30 — millions of dollars	2024	2023
Interconnection agreements	$ 282.3	$ 248.3
Phase 2 Implementation Plan (P2IP) Settlement Agreement	232.5	242.8
Irrigation assistance	214.3	—
Deferred project revenue funded in advance	142.3	144.8
Resilient Columbia Basin Agreement - Six Sovereigns	91.0	—
Operating leases	86.8	75.0
Third AC Intertie capacity agreements	80.2	82.6
Service deposits	79.3	48.2
Unearned revenue from customer deposits	73.9	66.0
Federal Employees’ Compensation Act	21.0	17.8
Fiber optic leasing fees	5.5	5.9
Other	1.8	2.6
Derivative instruments	1.7	1.8
Total	$ 1,312.6	$ 935.8

“**Interconnection agreements**” are advances for requested new network upgrades and interconnections. These advances accrue interest and will be returned as cash or credits against future transmission service on the new or upgraded lines.

“**Phase 2 Implementation Plan (P2IP) Settlement Agreement**” represents the undiscounted long-term portion of future payments to be made to certain Upper Columbia River tribes as agreed to in the P2IP Settlement Agreement signed in September 2023. Per the terms of the agreement, BPA will provide $10 million per year, beginning in fiscal year 2024 for the 20-year duration of the agreement, for a total of $200 million (adjusted for inflation). These funds are to be used to test the feasibility of, and ultimately reintroduce salmon in blocked habitats in the Upper Columbia River Basin. The Settlement Agreement became effective in October 2023 upon the dismissal of the related tribal litigation.

“Irrigation assistance” represents the long-term portion of future payments to be made to the U.S. Treasury in connection with the original construction costs of certain Pacific Northwest irrigation facilities. Amounts owed are representative of construction costs that are deemed to be beyond the irrigators ability to pay. (For further information, see Note 5, Effects of Regulation, and Note 14, Commitments and Contingencies.)

Estimated future payments for Irrigation assistance over the next five fiscal years are as follows: $13.3 million in 2025, $20.8 million in 2026, $6.4 million in 2027, $11.7 million in 2028 and $4.1 million in 2029. Payments made between fiscal years 2030 and 2045 are expected to total $171.3 million

“Deferred project revenue funded in advance” consists of third-party advances received where BPA will own the resulting transmission assets. The balance is amortized as other revenue not with customers over the life of the assets, so that the balance prevents any stranded costs in case of impairment as prescribed by the transmission rate process.

“**Resilient Columbia Basin Agreement – Six Sovereigns’**” represents the undiscounted long-term portion of future payments to be made to certain Lower Columbia River tribes and States (collectively known as the Six Sovereigns) in alignment with the settlement agreement signed in December 2023. Per the terms of this agreement, BPA will make available $10 million per year over ten years, beginning in fiscal year 2024 for a total of $100 million (adjusted for inflation). These funds are to be used for projects that contribute to the restoration of salmon and other native fish populations as prioritized by the Six Sovereigns. The $10 million associated with fiscal year 2024 has not yet been disbursed and BPA expects to make the fiscal year 2024 payment in fiscal year 2025.

“**Operating leases**” consists of long-term lease liabilities. (See Note 4, Leases.)

“**Third AC Intertie capacity agreements**” reflect unearned revenue from customers related to the Third AC Intertie transmission line capacity project. Revenue is recognized over an estimated 51-year life of the related assets, which are generally added and retired each year. (See Note 2, Revenue Recognition.)

“Service deposits” reflect required deposits for BPA products or services. The majority of these amounts are expected to be returned to the customer after a period of service.

“**Unearned revenue from customer deposits**” consists of advances received from customers for projects or studies undertaken at their request. Revenue is recognized as expenditures are incurred. (See Note 2, Revenue Recognition.)

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

“**Fiber optic leasing fees**” reflect unearned revenue related to the leasing of fiber optic cables. BPA recognizes revenue over the lease terms, which extend through 2025. (See Note 2, Revenue Recognition.)

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

12. Risk Management and Derivative Instruments

BPA is exposed to various forms of market risks related to commodity prices and volumes, counterparty credit and interest rates. Non-performance risk, which includes credit risk, is described in Note 13, Fair Value Measurements. BPA has formal risk management processes in place to manage agency risks, including the use of derivative instruments. The following sections describe BPA’s exposure to and management of certain risks.

RISK MANAGEMENT

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

COMMODITY PRICE RISK AND VOLUMETRIC RISK

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

CREDIT RISK

Credit risk relates to the loss that might occur as a result of counterparty non-performance. BPA mitigates credit risk by reviewing counterparties for creditworthiness, establishing credit limits and monitoring credit exposure. To further manage credit risk, BPA obtains credit support, such as letters of credit, parental guarantees, and cash in the form of prepayments, deposits or escrow funds, from some counterparties. BPA monitors counterparties for changes in financial condition and regularly updates credit reviews. BPA uses scoring models, publicly available financial information and external ratings from major credit rating agencies to determine appropriate levels of credit for its counterparties.

During fiscal year 2024, BPA experienced no material losses as a result of any customer defaults or bankruptcy filings. As of Sept. 30, 2024, BPA had $61 million in credit exposure related to purchase and sale contracts after taking into account netting rights. Of this $61 million, $59.7 million was related to investment grade counterparties and $1.3 million was related to sub-investment grade counterparties who provided letters of credit, cash collateral, or a combination of both. The letters of credit and collateral serve as a guarantee arrangement and mitigate BPA's credit risk exposure to these counterparties.

INTEREST RATE RISK

BPA has the ability to issue variable rate bonds to the U.S. Treasury. BPA may manage the interest rate risk presented by variable rate U.S. Treasury debt by holding U.S. Treasury security investments with a similar maturity profile. Such investments may earn interest that is correlated, but typically lower than, the interest rate paid on U.S. Treasury variable rate debt.

DERIVATIVE INSTRUMENTS

Commodity Contracts

BPA's forward electricity contracts are eligible for the normal purchases and normal sales exception if they require physical delivery, are expected to be used or sold by BPA in the normal course of business and meet the derivative accounting definition of capacity described in the derivatives and hedging accounting guidance. Transactions for which BPA has elected the normal purchases and normal sales exception are not recorded at fair value in the financial statements. Recognition of these contracts in Sales or Purchased power in the Combined Statements of Revenues and Expenses occurs when the contracts are delivered and settled.

For derivative instruments recorded at fair value, BPA offsets unrealized gains and losses as Regulatory assets and Regulatory liabilities on the Combined Balance Sheets. Realized gains and losses are included in Sales and Purchased power in the Combined Statements of Revenues and Expenses when the contracts are delivered and settled.

When available, quoted market prices or prices obtained through external sources are used to measure a contract's fair value. For contracts without available quoted market prices, fair value is determined based on internally developed modeled prices. (See Note 13, Fair Value Measurements.)

As of Sept. 30, 2024, the derivative commodity contracts recorded at fair value totaled 2.2 million megawatt hours (MWh), gross basis, with delivery months extending to September 2025.

On the Combined Balance Sheets, BPA reports net fair value amounts of derivative instruments subject to a master netting arrangement (excluding contracts designated as normal purchases or normal sales) in accordance with ASC 210 and 815. In the event of default or termination, contracts with the same counterparty are offset and net settle through a single payment. BPA does not offset cash collateral against recognized derivative instruments with the same counterparty under the master netting arrangements.

If reported gross, BPA's derivative position would have resulted in assets of $20 million and $51.9 million, and liabilities of $2.9 million and $2.2 million as of Sept. 30, 2024, and 2023, respectively. (See Note 5, Effects of Regulation.)

13. Fair Value Measurements

BPA applies fair value measurements and disclosures accounting guidance to certain assets and liabilities including assets held in trust funds, commodity derivative instruments, debt and other items. 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 exchange-traded financial futures, fixed income investments, equity mutual funds and money market funds.

Level 2 – Inputs other than quoted prices included within Level 1 that are either directly or indirectly observable for the asset or liability, including quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, inputs other than quoted prices that are observable for the asset or liability, and inputs that are derived from observable market data by correlation or other means. Instruments categorized in Level 2 include certain non-exchange traded commodity derivatives and certain agency, corporate and municipal securities as part of the Lease-Purchase trust funds investments. Fair value for certain non-exchange traded derivatives is based on forward exchange market prices and broker quotes adjusted and discounted. Lease-Purchase trust funds investments are based on a market input evaluation pricing methodology using a combination of observable market data such as current market trade data, reported bid/ask spreads, and institutional bid information.

Level 3 – Unobservable inputs for the asset or liability, including situations where there is little, if any, market activity for the asset or liability.

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

BPA includes non-performance risk when 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. 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, 2024, and 2023. There were no transfers between Level 2 and Level 3 during fiscal years 2024 and 2023.

ASSETS AND LIABILITIES MEASURED AT FAIR VALUE ON A RECURRING BASIS

As of Sept. 30, 2024 — millions of dollars

	Level 1	Level 2	Level 3	Total
Assets				
Nonfederal nuclear decommissioning trusts				
Equity securities	$ 516.4	$ —	$ —	$ 516.4
Debt securities	89.9	—	—	89.9
Cash and cash equivalents	17.2	—	—	17.2
Derivative instruments [1]				
Commodity contracts	0.8	2.5	15.5	18.8
Transmission line-related receivables	—	—	10.4	10.4
Total	$ 624.3	$ 2.5	$ 25.9	$ 652.7
Liabilities				
Derivative instruments [1]				
Commodity contracts	$ —	$ (1.7)	$ —	$ (1.7)
Total	$ —	$ (1.7)	$ —	$ (1.7)

As of Sept. 30, 2023 — millions of dollars

	Level 1	Level 2	Level 3	Total
Assets				
Nonfederal nuclear decommissioning trusts				
Equity securities	$ 396.1	$ —	$ —	$ 396.1
Debt securities	66.4	—	—	66.4
Cash and cash equivalents	17.0	—	—	17.0
Lease-Purchase trust funds				
U.S. government obligations	—	2.6	—	2.6
Derivative instruments [1]				
Commodity contracts	0.1	40.3	11.1	51.5
Transmission line-related receivables	—	—	10.4	10.4
Total	$ 479.6	$ 42.9	$ 21.5	$ 544.0
Liabilities				
Derivative instruments [1]				
Commodity contracts	$ —	$ (1.8)	$ —	$ (1.8)
Total	$ —	$ (1.8)	$ —	$ (1.8)

[1] Derivative instruments assets and liabilities are included in Deferred charges and other and Deferred credits and other, respectively, on the Combined Balance Sheets. See Note 12, Risk Management and Derivative Instruments for more information related to BPA's risk management strategy and use of derivative instruments.

Commodity contracts assets and liabilities classified as Level 3 consist of instruments for which fair value is derived using one or more significant inputs that are not observable for the entire term of the instrument. These instruments consist of power contracts measured at fair value on a recurring basis using the California-Oregon Border (COB) forward price curves. They include power contracts delivering to illiquid trading points or contracts without available market transactions for the entire delivery period. Forward prices are considered a key component to contract valuations. All valuation pricing data is generated internally by BPA's risk management organization.

Quantitative information regarding the only significant unobservable input used in the measurement of Level 3 commodity contract assets and liabilities is presented below:

	Fair Value		Valuation Technique	Significant Unobservable Input	Range (per MWh)		
	Assets[1]	Liabilities[1]			Low	High	Weighted Average
	(in millions)						
As of Sept. 30, 2024							
Physical forward power contracts	$ 15.5	$ —	Discounted cash flow	Electricity forward price	$ 29.8	$ 124.8	$ 85.3
As of Sept. 30, 2023							
Physical forward power contracts	$ 11.1	$ —	Discounted cash flow	Electricity forward price	$ 48.1	$ 183.8	$ 124.3

[1] The valuation techniques, unobservable inputs and ranges are the same for asset and liability positions

The significant unobservable input listed above is used by the risk management organization to construct the fair value through the use of available market prices, broker quotes and bid/offer spreads. In periods where market prices or broker quotes are not available, the risk management organization derives monthly prices by applying seasonal shaping based on historical broker quotes and spreads. Long-term prices are derived from internally developed or commercial models with both internal and external data inputs. BPA management believes this approach maximizes the use of pricing information from external sources and is currently the best option for valuation. Significant increases or decreases in the inputs would result in significantly higher or lower fair value measurements.

Forward power prices are influenced by, among other factors, the price of natural gas, seasonality, hydro forecasts, expectations of demand growth, and planned changes in the regional generating plants.

Transmission line-related receivables classified as Level 3 consist of a set of contracts executed between BPA and IPC governing the Purchase, Sale and Security provisions related to the transfer of BPA's permitting interest share in the proposed Boardman-to-Hemingway transmission line to IPC. (For further information on this transaction, see Note 7, Deferred Charges and Other.) These contracts determine whether, when and how much of BPA's contributions towards project security, initial design and permitting will be returned to BPA.

Significant unobservable inputs related to the Transmission line-related receivable asset are the occurrence of certain contingent contractual provisions and the energization of the underlying transmission line. These assessments result in expectations concerning specific future cash flows, which are currently estimated to occur between 2028 and 2047.

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

As of Sept. 30 — millions of dollars	2024	2023
Beginning Balance	$ 21.5	$ 12.5
Changes in unrealized gains (losses)[1]	4.4	(1.4)
Changes in Transmission line-related receivables	—	10.4
Ending Balance	$ 25.9	$ 21.5

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

DEBT

As of Sept. 30 — millions of dollars	2024		2023	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Nonfederal Debt				
Nonfederal generation:				
Columbia Generating Station	$ 3,434.4	$ 3,438.7	$ 3,381.9	$ 3,229.6
Cowlitz Falls Project	47.3	47.4	52.0	56.4
Terminated nonfederal generation:				
Nuclear Project 1	829.0	840.7	837.5	832.6
Nuclear Project 3	967.4	1,004.3	970.6	987.1
Northern Wasco Hydro Project	1.9	1.9	3.6	3.6
Lease-Purchase Program:				
Lease-purchase liability	1,671.7	1,408.5	1,766.8	1,372.2
NIFC debt	119.1	129.8	119.1	118.7
Other financial liability	15.4	9.5	16.0	8.5
Customer prepaid power purchases	111.7	111.7	139.2	139.2
Federal debt				
Borrowings from U.S. Treasury	$ 5,960.7	$ 5,349.1	$ 5,783.8	$ 4,756.6

The fair value measurements described above are considered Level 2 in the fair value hierarchy.

The fair value of Nonfederal debt, excluding Other financial liability and Customer prepaid power purchases, is primarily 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 fair value of Other financial liability is based upon discounted future cash flows using estimated interest rates for similar debt that could have been issued at Sept. 30, 2024, and 2023.

The opportunity to participate in the Customer prepaid power purchase program was made to a subset of BPA's power customers with repayment terms through billing credits extending to fiscal year 2028. Management believes that the customer prepaid power purchases are specific to BPA's operating environment and are nontransferable. As a result, the carrying value of customer prepaid power purchases is equal to its fair value.

The fair value of Borrowings from U.S. Treasury is based on discounted future cash flows using interest rates for similar debt that could have been issued at Sept. 30, 2024, and 2023.

The table above does not include Finance lease liabilities, a component of BPA's nonfederal debt. See Note 8, Debt and Appropriations, for the full carrying value of BPA's debt portfolio.

14. Commitments and Contingencies

INTEGRATED FISH AND WILDLIFE PROGRAM

The Northwest Power Act directs BPA to protect, mitigate and enhance fish and wildlife and their habitats to the extent they are affected by the federal hydroelectric projects on the Columbia River and its tributaries from which BPA markets power. BPA makes expenditures and incurs other costs for fish and wildlife protection and mitigation that are consistent with the purposes of the Northwest Power Act and the Pacific Northwest Power and Conservation Council's Columbia River Basin Fish and Wildlife Program. In addition, certain fish and wildlife species that inhabit the Columbia River Basin are listed under the Endangered Species Act (ESA) as threatened or endangered. BPA makes expenditures and incurs other costs related to power purposes to comply with the ESA and implement 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 (including results from the Columbia River System Operations (CRSO) Environmental Impact Statement). BPA's total commitment including timing of payments under the Northwest Power Act, ESA and BiOp, including CRSO Environmental Impact Statement impacts, is not fixed or determinable.

As of Sept. 30, 2024, BPA has long-term fish and wildlife agreements with estimated contractual commitments of $1.01 billion, which are likely to result in future expenses or regulatory assets. These agreements include the Columbia Basin Fish Accords, two non-accord long-term funding agreements with certain tribal partners and an agreement to fund certain Lower Snake River Compensation Plan (LSRCP) hatchery costs. BPA anticipates these agreements will result in future expenses or regulatory assets in the future as work progresses by the agreement partners in accordance with contractual terms.

Columbia Basin Fish Accords

BPA and its federal partners, USACE and Reclamation, have agreements with Accords partners, namely certain states and tribes, for fish and wildlife protection and mitigation. The Accords and associated BPA funding commitments facilitate implementation of projects that provide BPA with legal compliance actions under applicable laws, including the Northwest Power Act and Endangered Species Act, and that benefit Columbia River Basin fish and wildlife. As of Sept. 30, 2024, existing accord agreements commit approximately $502 million through Sept. 30, 2025. In October 2024, BPA signed an extension to an existing accord agreement which commits an additional $89 million through Sept. 30, 2034. These accords agreements will result in future expenses or regulatory assets as work progresses by accord partners in accordance with contractual terms.

Long-term funding agreements

In fiscal year 2024, and as a result of commitments made in the September 2023 P2IP Settlement Agreement, BPA signed two separate 10-year agreements with the Spokane Tribe of Indians and Coeur d'Alene Tribe to implement projects that promote the protection and restoration of fish and wildlife in the upper Columbia River Basin. Together these agreements originally committed approximately $311 million, after adjustment for inflation, expire in 2033 and will result in future expenses or regulatory assets. As of Sept. 30, 2024, approximately $306 million is available under these agreements. BPA anticipates recording liabilities and associated expenses or regulatory assets related to these agreements in the future as work progresses by the agreement partners in accordance with contractual terms.

U.S. Government Commitments in Support of the U.S. Fish and Wildlife Service for the Lower Snake River Compensation Plan

Additionally, in December 2023 the United States (including BPA and other federal partners), the States of Washington and Oregon, the Confederated Tribes and Bands of the Yakama Nation, the Confederated Tribes of the Umatilla Indian Reservation, the Confederated Tribes of the Warm Springs Reservation, the Nez Perce Tribe, and certain environmental non-profit organizations signed an agreement to further the restoration of native fish populations, while also providing reliable, affordable, and economic power and transmission. In connection with this agreement, BPA committed to make available $200 million over 10 years to the U.S. Fish and Wildlife Service for Lower Snake River Compensation Plan hatchery modernization, upgrades and maintenance. The use of these funds is guided by the priorities of the fishery managers including the states and tribal partners outlined above. BPA anticipates recording liabilities and associated regulatory assets related to these agreements in the future as work progresses by the state and tribal partners in accordance with contractual terms.

IRRIGATION ASSISTANCE

As directed by law, BPA is required to establish rates sufficient to make distributions to the U.S. Treasury for original construction costs of certain Pacific Northwest irrigation projects for which the costs 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.

Future irrigation assistance payments are scheduled to total $227.6 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.

In August 2024, BPA management implemented a new policy regarding the administration of the annual payment made to the U.S. Treasury. This policy establishes the irrigation assistance payment as a required component of the broader payment made to the U.S. Treasury each year. As such, in fiscal year 2024, BPA recorded $227.6 million representative of the outstanding liability as of Sept. 30, 2024. BPA also recorded a corresponding $227.6 million regulatory asset representing the BPA Administrator's decision to defer expense recognition to future rate periods. (For further information regarding these amounts see Note 5, Effects of Regulation, and Note 11, Deferred Credits and Other.) Prior to fiscal year 2024, distributions were not considered to be regular operating costs of the power program and were treated as distributions from accumulated net revenues when paid. Beginning with fiscal year 2024, these distributions are recorded as a non-operating expense in the year of payment and in connection with the amortization of the regulatory asset.

FIRM PURCHASE POWER COMMITMENTS

Years ended Sept. 30 — millions of dollars		
2025	$	41.0
2026		43.8
Total	$	84.8

BPA periodically enters into long-term commitments to purchase power for future delivery. When BPA forecasts a resource shortage, based on its planned contractual obligations for a period and the historical water record for the Columbia River basin, BPA takes a variety of operational and business steps to cover a potential shortage including entering into power purchase commitments. Additionally, under BPA's current Tiered Rates Methodology and its current Regional Dialogue power sales contracts, BPA's customers may request that BPA meet their power requirements in excess of the Rate Period High Water Mark load under their contract. For these Above High Water Mark load requests, BPA may meet such requests by entering into power purchase commitments.

The preceding table includes firm purchase power agreements that are currently in place to assist in meeting expected future obligations under BPA's current long-term power sales contracts. Included are three purchases to meet load obligations in Idaho. Power purchase agreements to satisfy load obligations in Idaho utilize variable pricing. Variable pricing arrangements are based on the current market price of energy on the date of delivery. The expenses associated with the Idaho purchases were $52.1 million, $74.9 million and $7.6 million for fiscal years 2024, 2023 and 2022, respectively. BPA has several other purchase agreements with wind-powered and other generating facilities that are not included in the preceding table as payments are based on the variable amount of future energy generated and as there are no minimum payments required.

ENERGY EFFICIENCY PROGRAM

BPA is required by the Northwest Power Act to meet the net firm power load requirements of its customers in the Pacific Northwest. BPA is authorized to help meet its net firm power load through the acquisition of electric conservation. BPA makes available a portfolio of initiatives and infrastructure support activities to its customers to ensure the conservation targets established in the Northwest Power and Conservation Council's then-current Power Plan are achieved. The Council released the 2021 Northwest Power Plan in fiscal year 2022. These initiatives and activities are often executed via conservation commitments made by BPA to its customers through 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 2028. Conservation-related expenses are recorded to operations and maintenance expense as incurred.

1989 ENERGY NORTHWEST LETTER AGREEMENT

In 1989, BPA agreed with Energy Northwest that, in the event any participant shall be unable for any reason, or shall fail or refuse, to pay to Energy Northwest any amount due from such participant under its net billing agreement for which a net billing credit or cash payment to such participant has been provided by BPA, BPA will be obligated to pay the unpaid amount in cash directly to Energy Northwest. As of Sept. 30, 2024, and 2023, no amounts have been accrued related to this agreement.

NUCLEAR INSURANCE

BPA is a member of 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 for CGS include: 1) Primary Property and Decontamination Liability Insurance; 2) Excess Property, Excess Decontamination Liability and Decommissioning Liability 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 $19.8 million. For the Excess Property, Excess Decontamination Liability and Decommissioning Liability Insurance policy, the maximum assessment is $7.1 million. For the NEIL I Accidental Outage Insurance policy, the maximum assessment is $6.5 million.

Additionally, in the event of a nuclear accident resulting in public liability losses exceeding $450 million under the Nuclear Regulatory Commission's indemnity for public liability coverage under the Price-Anderson Act, BPA could be subject to a retrospective assessment of up to $165.9 million limited to $24.7 million per incident within one calendar year. Assessments would be included in BPA's costs and recovered through rates. As of Sept. 30, 2024, there have been no assessments payable by BPA under any of these events.

ENVIRONMENTAL MATTERS

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

INDEMNIFICATION AGREEMENTS

BPA, USACE and Reclamation have provided indemnifications of varying scope and terms in contracts with customers, vendors, lessors, trustees, and other parties with respect to certain matters including, but not limited to, losses arising out of particular actions taken on behalf of the FCRPS, certain circumstances related to Energy Northwest Projects, and in connection with lease-purchases. Because of the absence of a maximum obligation in the provisions, management is not able to reasonably estimate the overall maximum potential future payments. Based on historical experience and current evaluation of circumstances, management believes that as of Sept. 30, 2024, the likelihood is remote that the FCRPS would incur any significant costs with respect to such indemnities. No liability has been recorded in the financial statements with respect to these indemnification provisions.

RESERVES DISTRIBUTION CLAUSE

The Reserves Distribution Clause (RDC) is a rate adjustment mechanism that triggers if reserves for risk levels exceed certain cash on hand targets at September 30 for Power Services or Transmission Services. Terms of the RDC are discussed in the BP-24 and BP-22 rate cases, which state that the BPA Administrator shall consider above-threshold financial reserves for debt reduction, incremental capital investment, rate reduction through a Dividend Distribution, distribution to customers, or any Power- or Transmission-specific purposes determined by the Administrator.

Based upon fiscal year 2024 financial results and year-end reserves for risk levels for Transmission services, a Transmission RDC is expected to occur for application in fiscal year 2025. BPA’s Administrator will determine final amounts and use of the fiscal year 2025 Transmission RDC by Dec. 15, 2024, with application of most RDC actions likely to occur between December and September of fiscal year 2025. Based on fiscal year 2024 results and year-end reserves for risk levels for Power services, a Power RDC is not expected to occur for application in fiscal year 2025.

Based on fiscal year 2023 financial results and year-end reserves for risk levels for both Power and Transmission Services, an RDC occurred for application in fiscal year 2024. BPA’s Administrator determined final amounts and use of the Power and Transmission RDC during fiscal year 2024, and application of most RDC actions occurred between December and September of fiscal year 2024.

As of Sept. 30, 2024, and 2023, no liability had been accrued for the RDC.

LITIGATION

Rates

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

Other

The FCRPS may be affected by various other claims, actions and complaints, including claims regarding litigation under the Endangered Species Act, which may include BPA as a named party. Certain of these cases may involve material amounts including operational changes at FCRPS federal dams that may restrict hydroelectric generation. Management is unable to predict whether the FCRPS will avoid adverse outcomes in these legal matters.

Judgments and settlements are included in FCRPS costs and recovered through rates. As of Sept. 30, 2024, no material liability has been recorded for the above legal matters.

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APPENDIX B-2

Federal Columbia River Power System

Combined Balance Sheets (Unaudited)

(Millions of Dollars)	As of March 31, 2025	As of September 30, 2024
Assets		
Utility plant and nonfederal generation		
Completed plant	**$ 22,543.3**	$ 22,235.9
Accumulated depreciation	**(8,784.5)**	(8,604.9)
Net completed plant	**13,758.8**	13,631.0
Construction work in progress	**2,444.9**	2,236.4
Net utility plant	**16,203.7**	15,867.4
Nonfederal generation	**3,514.5**	3,410.0
Net utility plant and nonfederal generation	**19,718.2**	19,277.4
Current assets		
Cash and cash equivalents	**1,492.9**	1,412.0
Accounts receivable, net of allowance	**64.7**	95.4
Accrued unbilled revenues	**342.7**	348.2
Materials and supplies, at average cost	**143.7**	140.5
Prepaid expenses	**76.7**	81.0
Total current assets	**2,120.7**	2,077.1
Other assets		
Regulatory assets	**3,965.9**	4,153.4
Nonfederal nuclear decommissioning trusts	**615.7**	623.5
Deferred charges and other	**173.3**	169.6
Total other assets	**4,754.9**	4,946.5
Total assets	**$ 26,593.8**	$ 26,301.0

This BPA-approved financial information was made publicly available on 4-25-2025.

Federal Columbia River Power System

Combined Balance Sheets (Unaudited)

(Millions of Dollars)

	As of March 31, 2025	As of September 30, 2024
Capitalization and Liabilities		
Capitalization and long-term liabilities		
Accumulated net revenues	**$ 5,684.6**	$ 5,456.9
Debt		
Federal appropriations	**1,715.2**	1,697.1
Borrowings from U.S. Treasury	**5,694.5**	5,846.7
Nonfederal debt	**6,746.1**	6,779.3
Total capitalization and long-term liabilities	**19,840.4**	19,780.0
Commitments and contingencies (See Note 14 to 2024 Audited Financial Statements)		
Current liabilities		
Debt		
Borrowings from U.S. Treasury	**430.3**	114.0
Nonfederal debt	**629.0**	521.9
Accounts payable and other	**745.8**	869.1
Total current liabilities	**1,805.1**	1,505.0
Other liabilities		
Regulatory liabilities	**1,491.5**	1,522.4
IOU exchange benefits	**925.0**	1,062.8
Asset retirement obligations	**1,137.4**	1,118.2
Deferred credits and other	**1,394.4**	1,312.6
Total other liabilities	**4,948.3**	5,016.0
Total capitalization and liabilities	**$ 26,593.8**	$ 26,301.0

This BPA-approved financial information was made publicly available on 4-25-2025.

Federal Columbia River Power System

Combined Statements of Revenues and Expenses (Unaudited)

(Millions of Dollars)

	Three Months Ended March 31,		Fiscal Year-to-Date Ended March 31,	
	2025	2024	**2025**	2024
Operating revenues				
Sales	**$ 1,100.2**	$ 1,210.5	**$ 2,155.8**	$ 2,239.2
U.S. Treasury credits	**55.7**	146.8	**98.3**	226.5
Total operating revenues	**1,155.9**	1,357.3	**2,254.1**	2,465.7
Operating expenses				
Operations and maintenance	**652.8**	621.5	**1,277.0**	1,180.3
Purchased power	**196.9**	617.4	**302.5**	846.0
Depreciation, amortization and accretion	**223.0**	216.7	**440.3**	433.4
Total operating expenses	**1,072.7**	1,455.6	**2,019.8**	2,459.7
Net operating revenues (expenses)	**83.2**	(98.3)	**234.3**	6.0
Interest expense and other income, net				
Interest expense	**115.8**	113.4	**228.9**	226.9
Irrigation assistance	**3.3**	-	**6.7**	-
Allowance for funds used during construction	**(17.5)**	(13.1)	**(34.7)**	(26.1)
Interest income	**(8.6)**	(12.2)	**(16.3)**	(29.2)
Other, net	**(170.2)**	(1.8)	**(178.0)**	(8.7)
Total interest expense and other income, net	**(77.2)**	86.3	**6.6**	162.9
Net revenues (expenses)	**$ 160.4**	$ (184.6)	**$ 227.7**	$ (156.9)

This BPA-approved financial information was made publicly available on 4-25-2025.

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Independent Auditors' Report

To the Executive Board of
Energy Northwest

Report on the Audit of the Financial Statements

Opinions

We have audited the financial statements of the business-type activities of Energy Northwest, as of and for the year ended June 30, 2024, and the related notes to the financial statements, which collectively comprise Energy Northwest's basic financial statements as listed in the table of contents.

In our opinion, the accompanying financial statements referred to above present fairly, in all material respects, the financial position of the business-type activities of Energy Northwest as of June 30, 2024, and the changes in financial position and cash flows for the year then ended in accordance with accounting principles generally accepted in the United States of America.

Basis for Opinions

We conducted our audit in accordance with auditing standards generally accepted in the United States of America (GAAS) and the standards applicable to financial audits contained in *Government Auditing Standards* issued by the Comptroller General of the United States (*Government Auditing Standards).* Our responsibilities under those standards are further described in the Auditors' Responsibilities for the Audit of the Financial Statements section of our report. We are required to be independent of Energy Northwest and to meet our other ethical responsibilities, in accordance with the relevant ethical requirements relating to our audit. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinions.

Responsibilities of Management for the Financial Statements

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

In preparing the financial statements, management is required to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about Energy Northwest's ability to continue as a going concern for twelve months beyond the financial statement date, including any currently known information that may raise substantial doubt shortly thereafter.

Auditors' Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinions. Reasonable assurance is a high level of assurance but is not absolute assurance and therefore is not a guarantee that an audit conducted in accordance with GAAS and *Government Auditing Standards* will always detect a material misstatement when it exists. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations or the override of internal control. Misstatements are considered material if there is a substantial likelihood that, individually or in the aggregate, they would influence the judgment made by a reasonable user based on the financial statements.

In performing an audit in accordance with GAAS and *Government Auditing Standards*, we:

- Exercise professional judgment and maintain professional skepticism throughout the audit.
- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, and design and perform audit procedures responsive to those risks. Such procedures include examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Energy Northwest's internal control. Accordingly, no such opinion is expressed.
- Evaluate the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluate the overall presentation of the financial statements.
- Conclude whether, in our judgment, there are conditions or events, considered in the aggregate, that raise substantial doubt about Energy Northwest's ability to continue as a going concern for a reasonable period of time.

We are required to communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit, significant audit findings and certain internal control-related matters that we identified during the audit.

Required Supplementary Information

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

Additional Information

Management is responsible for the accompanying information included in the annual report (the “additional information”), which is presented for purposes of additional analysis and is not a required part of the basic financial statements. Our opinions on the basic financial statements do not cover the additional information, and we do not express an opinion or any form of assurance thereon.

Other Reporting Required by *Government Auditing Standards*

In accordance with *Government Auditing Standards*, we have also issued our report dated September 26, 2024 on our consideration of Energy Northwest's internal control over financial reporting and on our tests of its compliance with certain provisions of laws, regulations, contracts and grant agreements and other matters. The purpose of that report is solely to describe the scope of our testing of internal control over financial reporting and compliance and the results of that testing, and not to provide an opinion on the effectiveness of Energy Northwest's internal control over financial reporting or on compliance. That report is an integral part of an audit performed in accordance with *Government Auditing Standards* in considering Energy Northwest's internal control over financial reporting and compliance.

Baker Tilly US, LLP

Madison, Wisconsin
September 26, 2024

Energy Northwest Management's Discussion and Analysis (Unaudited)

Energy Northwest is a municipal corporation and joint operating agency of the state of Washington. Each Energy Northwest business unit is financed and accounted for separately from all other current or future business assets. The following discussion and analysis is organized by business unit. The management discussion and analysis of the financial performance and activity is provided as an introduction and to aid in comparing the basic financial statements for the fiscal year (FY) ended June 30, 2024, with the basic financial statements for the FY ended June 30, 2023.

Energy Northwest has adopted accounting policies and principles that are in accordance with Generally Accepted Accounting Principles (GAAP) in the United States of America. Energy Northwest's records are maintained as prescribed by the Governmental Accounting Standards Board (GASB). (See Note 1 to the Financial Statements.)

Because each business unit is financed and accounted for separately, the following section on financial performance is discussed by business unit to aid in analysis of assessing the financial position of each individual business unit. For comparative purposes only, the table on the following page represents a memorandum only total for Energy Northwest, as a whole, for FY 2024 and FY 2023.

The Financial Statements for Energy Northwest include the Statements of Net Position; Statements of Revenues, Expenses, and Changes in Net Position; and Statements of Cash Flows for each of the business units, and Notes to Financial Statements.

The Statements of Net Position present the financial position of each business unit on an accrual basis. The Statements of Net Position report financial information about construction work in progress, the amount of resources and obligations, restricted accounts, and due to/from balances for each business unit. (See Note 1 to the Financial Statements.)

The Statements of Revenues, Expenses, and Changes in Net Position provide financial information relating to all expenses, revenues and equity that reflect the results of each business unit and its related activities over the course of the fiscal year. The financial information provided aids in benchmarking activities, conducting comparisons to evaluate progress, and determining whether the business unit has successfully recovered its costs.

The Statements of Cash Flows reflect cash receipts and disbursements and net changes resulting from operating, financing, and investing activities. The Statements of Cash Flows provide insight into what generates cash, where the cash comes from, and purpose of cash activity.

The Notes to Financial Statements present disclosures that contribute to the understanding of the material presented in the financial statements. This includes, but is not limited to, Schedule of Outstanding Long-Term Debt and Debt Service Requirements (See Note 4 to the Financial Statements), accounting policies, significant balances and activities, material risks, commitments and obligations, and subsequent events, if applicable.

The basic Financial Statements of each business unit along with the Notes to the Financial Statements and Management Discussion and Analysis should be used to provide an overview of Energy Northwest's financial performance. The following discussion provides comparative financial information for the years ended June 30, 2024, and 2023. Questions concerning any of the information provided in this report should be addressed to Energy Northwest at PO Box 968, Richland, WA, 99352.

Combined Financial Information - June 30, 2024 and 2023 (Dollars in thousands)

	2023	2024	Change
Assets			
Current Assets	$ 571,771	$ 619,663	$ 47,892
Net Plant	1,741,001	1,746,978	5,977
Nuclear Fuel	421,933	406,306	(15,627)
Long-Term Receivables	1,939	3,494	1,555
Pension Asset restricted	44,440	45,190	750
Other non current restricted assets	143,399	306,354	162,955
Other Assets	4,024,089	3,897,750	(126,339)
TOTAL ASSETS	6,948,572	7,025,735	77,163
DEFERRED OUTFLOWS OF RESOURCES	858,306	943,303	84,997
TOTAL ASSETS AND DEFERRED OUTFLOWS	$ 7,806,878	$ 7,969,038	$ 162,160
Current Liabilities	$ 247,366	$ 292,220	$ 44,854
Restricted Liabilities			
Debt Service Funds	118,382	124,170	5,788
Long-Term Debt	5,512,261	5,479,404	(32,857)
Other Long-Term Liabilities	1,831,366	1,965,147	133,781
Other Credits	9,434	10,068	634
Net Position			
Invested in capital assets, net of related debt	(13,186)	745	13,931
Restricted for decommissioning	3,220	6,612	3,392
Restricted for debt service, net	10,256	3,959	(6,297)
Restricted for pension asset, net	2,073	2,123	50
Unrestricted, net	10,651	13,065	2,414
TOTAL LIABILITIES AND NET POSITION	7,731,823	7,897,513	165,690
DEFERRED INFLOWS OF RESOURCES	75,055	71,525	(3,530)
TOTAL LIABILITIES, NET POSITION AND DEFERRED INFLOWS	$ 7,806,878	$ 7,969,038	$ 162,160
Operating Revenues	$ 548,394	$ 541,865	$ (6,529)
Operating Expenses	464,581	451,619	(12,962)
Net Operating Revenues	83,813	90,246	6,433
Other Income and Expenses	(81,295)	(82,996)	(1,701)
Capital Contribution	1,920	6,240	4,320
Beginning Net Position	8,576	13,014	4,438
ENDING NET POSITION	$ 13,014	$ 26,504	$ 13,490

Columbia Generating Station

Columbia Generating Station (Columbia) is wholly owned by Energy Northwest and its participants and operated by Energy Northwest. The plant is a 1,174-megawatt electric (MWe, Design Electric Rating, net) boiling water nuclear power plant located on the Department of Energy's (DOE) Hanford Site north of Richland, Washington.

Columbia produced 9,928 gigawatt-hours (GWh) of electricity in FY 2024 as compared to 8,630 GWh, which included 93 GWH of cost down credit in FY 2023. The 93 GWh of coast down credit in FY 2023 was approved by the Executive Board (coast down credit is a prudent utility practice to optimize fuel efficiency as part of General Electric's fuel design). Bonneville Power Administration did not grant credit to Columbia in FY 2023 to overall generation as a result of management directed coast down decisions.

Columbia's cost performance is measured by the cost of power indicator. The cost of power for FY 2024 was 3.89 cents per kilowatt-hour (kWh) as compared with 5.04 cents per kWh in FY 2023. The generating cost of power fluctuates year to year depending on various factors such as refueling outages and other planned activities. The FY 2024 cost of power decrease of 22.8% was due to reduced costs and the increased generation levels due to FY 2024 being a non-refueling outage year, as compared to FY 2023 being a refueling outage year.

Assets, Liabilities, and Net Position Analysis

The net increase to Utility Plant (plant) and Construction Work in Progress (CWIP) from FY 2023 to FY 2024 (excluding nuclear fuel) was $4.7 million. The changes to plant and CWIP were comprised of additions to plant of $25.6 million, $0.1 million of subscription asset, and an increase to CWIP of $79.1 million. Remaining change was the period effect of depreciation of $99.2 million of plant assets, $0.8 million of lease asset amortization, and $0.1 million of subscription asset amortization.

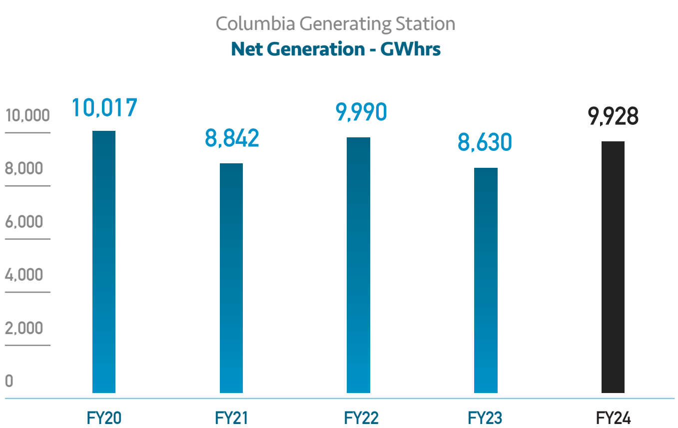
The FY 2024 CWIP balance of $166.3 million consisted of nine major projects of at least $1.5 million: Control Rod Drive Refurbishment, Main Turbine Valve Maintenance, Moisture Separator Reheater Internals Retrofitting, Reactor Recirculation Motor Replacement, Replace Normal Transformer 1, High Pressure Turbine Replacement, Plant Processing Computer Replacement Phase 1, Extended Power Uprate, Adjustable Speed Drive Replacement. These projects over $1.5 million result in 67.3% of the current CWIP balance. The remaining 32.7% of CWIP is comprised of 105 separate projects.

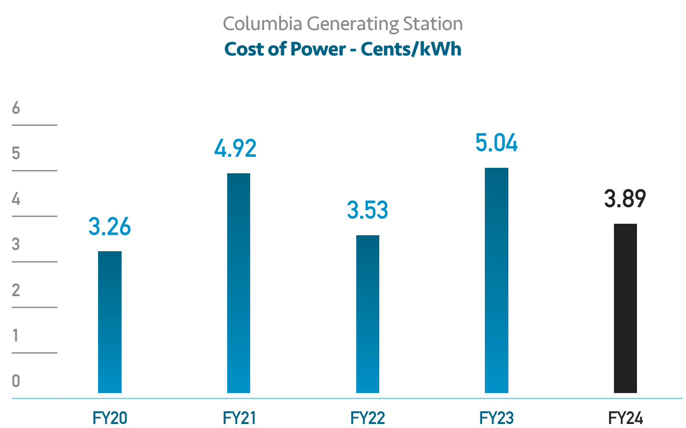
Nuclear fuel, net of accumulated amortization, decreased $15.6 million from FY 2023 to $406.3 million in FY 2024. During FY 2024 Columbia there was an increase of $35.7 million in capitalized fuel/reload activity. A decrease to spent fuel of $103.1 million reflects the original cost of fuel assemblies removed from R-26 and past the required six-month cooling period per the Federal Energy Regulatory Commission (FERC) guidelines. Accumulated fuel burnup amortization decreased $51.8 million due to the net of the fuel burnup amortization for the fuel assemblies removed from R-26 and the FY 2024 fuel burnup amortization. (See Note 11).

Current assets increased $52.4 million in FY 2024 to $503.9 million. The changes were increases to current restricted assets of $108.7 million due to the FY 2024 bond funding activities and bond restructuring associated with the regional cooperation debt program, increase to materials and supplies of $12.9 million, and an increase in prepayments of $0.7 million. The current asset increases were offset by a decrease to cash and investments of $39.6 million, and a decrease in receivables of $30.3 million.

Non-current lease receivable increased $1.5 million to $3.0 million in FY 2024.

Non-current restricted assets increased $159.5 million to $334.5 million in FY 2024. The changes were an increase to long-term debt service funds of $158.8 million due to





the FY 2024 bond funding activities and bond restructuring associated with the regional cooperation debt program. Also, an increase to pension asset in accordance with GASB No. 68 of $0.7 million (See Note 6).

Other Assets decreased $90.7 million from $2.105 billion in FY 2023 to $2.014 billion in FY 2024. The decrease was Costs in Excess of Billings related to the net effect of payment of current maturities and refunding activity associated with the regional cooperation debt program.

Deferred outflows increased $86.1 million in FY 2024 from $845.9 million to $932.0 million. The changes were an increase of $93.8 million in deferred decommissioning outflow due to an asset retirement adjustment ($78.8 million - Columbia, $15.0 million - ISFSI) due to a new asset retirement obligation (ARO) study being completed in FY 2024 and the yearly indexing requirements of GASB No. 83 (See Note 9). The increases were offset by a decrease of $6.6 million in the recognition of a deferred pension outflow in accordance with GASB No. 68 (See Note 6), and a decrease of $1.1 million to unamortized loss on refunding associated with the 2024 bond activity.

Current liabilities increased $49.4 million in FY 2024 to $239.4 million. The change included an increase in current maturities of long-term debt of $105.4 million per the maturity schedule for bonds, and an increase from timing of $10.8 million in due to other business units, which is a timing result of year-end obligations. Offsetting the increases were decreases in the current line of credit of $26.8 million, accounts payable of $7.7million, and a decrease in accrued expenses of $2.6 million, which includes the current lease liability recognized due to GASB 87 (See Note 13), and the current Subscription-Based Information Technology Arrangements liability. In addition, there was a decrease from timing of $29.7 million in due to participants.

Restricted liabilities increased $4.1 million in FY 2024 to $78.2 million due to the FY 2024 bond restructuring and funding activities associated with the regional cooperation debt program.

Long-term debt (Bonds Payable) increased $15.3 million in FY 2024 from $3.570 billion to $3.585 billion due to the FY 2024 bond restructuring and funding activities associated with the regional cooperation debt program.

Other long-term liabilities increased $129.5 million in FY 2024 to $1.932 billion. The major driver was an increase in the ARO due to a new ARO study being completed in FY 2024 and the yearly indexing of the obligation required by GASB No. 83 (See Note 9). Decommissioning liability increased $136.2 million. Columbia accounted for $120.1 million of the increase and ISFSI accounted for $16.1 million of the increase. Offsetting the increases was a decrease in the pension liability of $5.6 million in accordance with GASB No. 68 (See Note 6), and a decrease in the other postemployment benefits liability of $0.3 million in accordance with GASB No. 75 (See Note 12) and a decrease in long-term lease liability of $0.8 million in accordance with GASB 87 (See Note 13).

Costs associated with cask activity are no longer being recorded as a long-term liability as all costs have been deemed reimbursable under the agreement with DOE and reimbursements, per each approved submittal, will be offset against costs incurred (See Note 11).

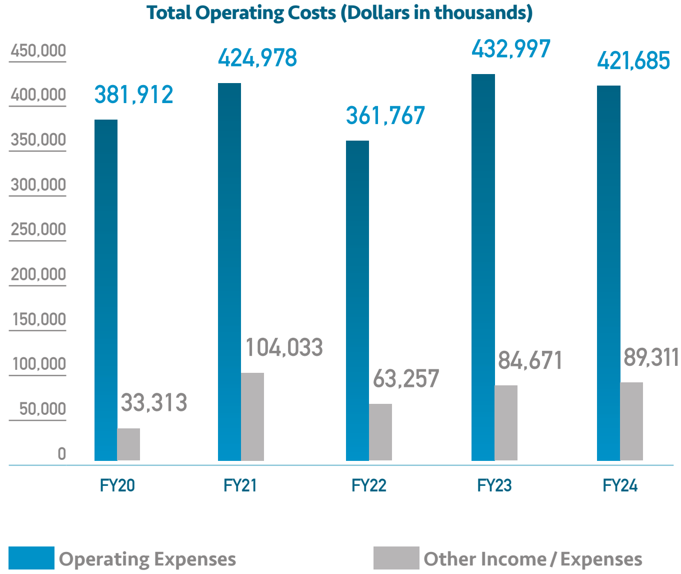
Deferred inflows decreased $0.5 million from $56.4 million in FY 2023 to $55.9 million in FY 2024. A decrease of $20.4 million was in deferred pension inflow in accordance with GASB No. 68 (See Note 6), a decrease in other postemployment benefits inflow of $0.4 million in accordance with GASB No. 75 (See Note 12). Offsetting the decreases was an increase in bond refunding inflows of $18.5 million due to the FY 2024 bond restructuring and funding activities associated with the regional cooperation debt program. Also, an increase in deferred lease inflows of $1.8 million to $3.7 million in FY 2024 in accordance with GASB 87 (See Note 13). Deferred credits for FY 2024 consisted of unclaimed bearer bonds and remained at the same level as FY 2023.

Revenue and Expenses Analysis

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

Operating expenses decreased $11.3 million from FY 2023 costs of $433.0 million to $421.7 million in FY 2024. The major decrease in costs was due to FY 2024 being a non-

Columbia Generating Station
Total Operating Costs (Dollars in thousands)



refueling year as compared to FY 2023 being a refueling year (R-26). The decrease in FY 2024 was in the operations and maintenance area ($114.5 million). Offsetting the decrease was an increase in administration and general expenses of $80.1 million in FY 2024. Increase in decommissioning of $7.0 million due to annual indexing requirements of the obligation related to GASB No. 83. Increases in nuclear fuel and generation taxes of $13.4 million and $0.2 million, respectively, due to increased generation because of FY 2024 being a non-refueling year. Finally, there was an increase of $2.5 million for depreciation and amortization due to more plant assets being placed in-service.

Other Income and Expenses increased $4.6 million from FY 2023 to $89.3 million net expenses in FY 2024. A gain of $15.1 million was recognized in FY 2024 on the spent fuel litigation settlement from the DOE, which was $12.9 million more than FY 2023. The cask costs were never an intended cost for the facility and only resulted from a failure to perform from the Department of Energy (See Note 10). Fuel disposal is no longer being recognized as part of the DOE settlement for this reason and any future recoveries from the DOE will be recorded in similar fashion. In FY 2024 there was not a gain on sale of Separative Work Units as the final sale to the Tennessee Valley Authority occurred in FY 2023 and thus there was decrease of $19.0 million from FY 2023. In FY 2023, there was a one-time sale of operational procedures to the Business Development Fund for a gain of $1.5 million, but there was not a similar sale in FY 2024, which results in a decrease of $1.5 million. In FY 2024, there was a decrease of $0.6 million in Build American Bonds revenue as compared to FY 2023. Bond interest expenses and amortization costs of $118.3 million were incurred as part of the FY 2024 planned and approved regional cooperation debt program, however, these were higher in FY 2024 by $1.5 million as compared to FY 2023. There was a net increase in expenses of $1.0 million related to leased buildings in FY 2024. The remaining change of $6.1 million was due to increases in investment income for FY 2024 as compared to FY 2023.

Columbia's total operating revenue decreased from $517.7 million in FY 2023 to $511.0 million in FY 2024. The decrease of $6.7 million was due to the off-cycle year of the two-year refueling plan and the related effect of the net billing agreement on total revenue (See Note 5).

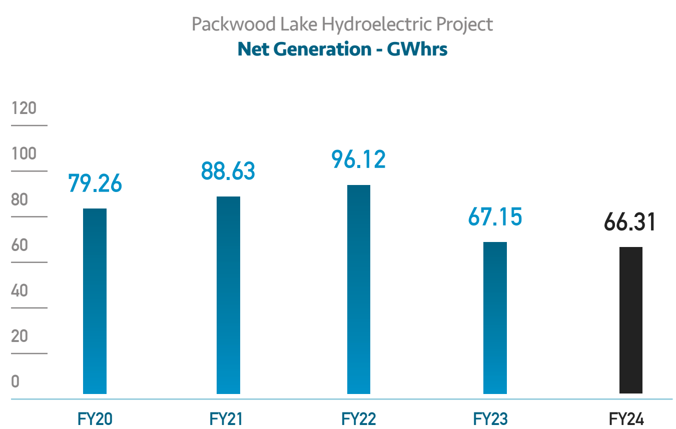
In FY 2024 Columbia received $5 thousand of contributed capital towards the Advanced Remote Monitoring project as compared to $9 thousand received in FY 2023. Energy Northwest entered into an agreement with the Utilities Service Alliance, who received a grant from the Department of Energy, to develop an Advanced Remote Monitoring system for nuclear plants.

Packwood Lake Hydroelectric Project

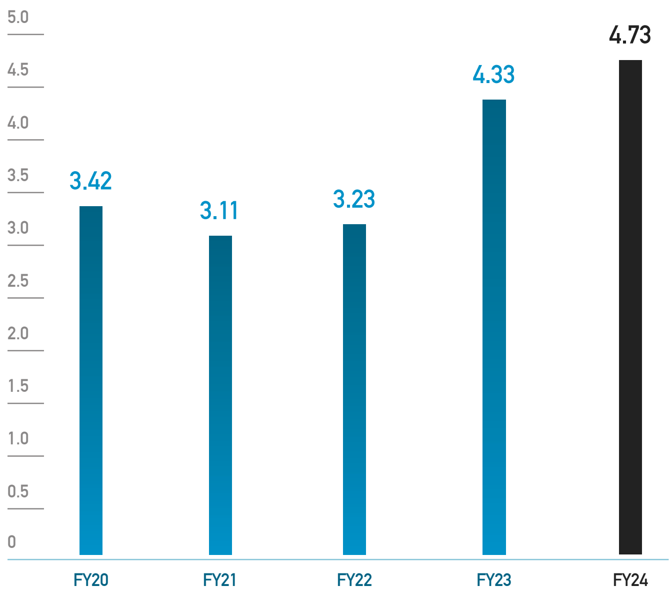
The Packwood Lake Hydroelectric Project (Packwood) is wholly owned and operated by Energy Northwest. Packwood consists of a diversion structure at Packwood Lake and a powerhouse located near the town of Packwood, Washington. The water is carried from the lake to the powerhouse through a five-mile long buried tunnel and drops nearly 1,800 feet in elevation. Packwood produced 66.31 GWh of electricity in FY 2024 versus 67.15 GWh in FY 2023. The generation decrease of 1.3% was due to lower water levels at Packwood Lake in FY 2024. In FY 2024, Packwood's generation was lower than the last five-year average net generation of 79.49 GWh. The generation for FY 2024 was below the life to date average per year of 93.00 GWh.

Packwood had been operating under a fifty-year license issued by FERC, which expired on February 28, 2010. Energy Northwest submitted the Final License Application (FLA) for renewal of the operating license to FERC on February 22, 2008. On March 4, 2010, FERC issued a one-year extension to operate under the original license, which indefinitely extended for continued operations until a formal decision was issued by FERC and a new operating license granted. On March 21, 2018, the National Oceanic and Atmospheric Administration/National Marine Fisheries Service (NOAA/NMFS) filed to the FERC the Biological Opinion (BiOp) of the Endangered Species Act for the relicensing of Packwood. On October 11, 2018, FERC issued the forty-year operating license effective October 1, 2018 (See Note 1 to the Financial Statements). The relicensing cost of $3.7 million incurred in previous years was transferred to intangible plant in FY 2019 and is being amortized over the forty-year license issued October 2018.

Packwood's cost performance is measured by the cost of power indicator. The cost of power for FY 2024 was 4.73 cents per kWh as compared to 4.33 cents per kWh in FY 2023. The cost of power fluctuates year-to-year depending on various



Packwood Lake Hydroelectric Project
Cost of Power - Cents/kWh



factors such as outage, maintenance, generation, and other operating costs. The increase (9.2%) in the FY 2024 cost of power was driven by a combination of higher operations and maintenance (O&M) costs and the decrease in generation noted above.

Assets, Liabilities, and Net Position Analysis

Total assets and deferred outflows increased $0.3 million in FY 2024 to $10.6 million. The net increase to Plant from FY 2023 to FY 2024 was $0.6 million. The increase to plant was offset by the period effect of depreciation of $0.3 million. Current assets decreased $0.3 million due to timing reduction in cash activities of $0.6 million at the end of the fiscal year offset by the timing increase of investments of $0.3 million. Restricted assets and deferred outflows remained static for FY 2024 as compared to FY 2023.

Total liabilities, net position and deferred inflows increased $0.3 million in FY 2024 to $10.6 million. There was an increase to other liabilities of $0.6 million related to advances from members and others. Current liabilities decreased $0.2 million due to a reduction in due to participants, and there was a decrease to deferred pension inflow of $0.1 million. Pension deferrals are recognized in accordance with GASB No. 68 (See Note 6).

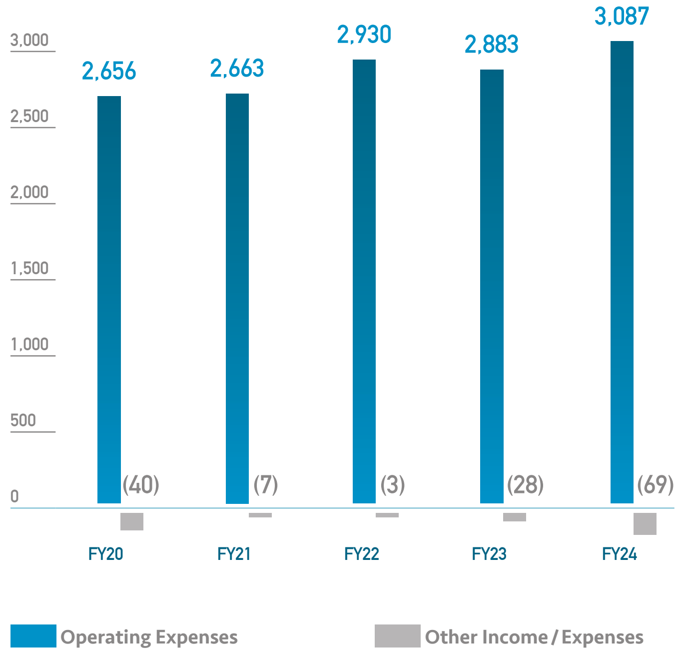
Revenue and Expenses Analysis

The agreement with Packwood participants obligates them to pay annual costs and to receive excess revenues. (See Note 1 to the Financial Statements.) Accordingly, Energy Northwest recognizes revenues equal to expenses for each period. No net revenue or loss is recognized, and no net position is accumulated. Operating expenses increased $0.2 million in FY 2024 as compared to FY 2023, mostly related to an increase in O&M costs.

Other Income and Expense comprised of gain on sale of $17 thousand and investment income of $54 thousand which is an increase in investment income of $25 thousand from FY 2023 to FY 2024.

Packwood participants are obligated to pay annual costs of the project (including any applicable debt service), whether or not the project is operable. The Packwood participants also share project revenue to the extent that the amounts exceed costs. These funds can be returned to the participants or kept within the project. As of June 30, 2024, there is $9.6 million recorded as other liabilities that are advances from members and others being kept within the project. Packwood participants are currently taking 100% of the project generation; there are no additional agreements for power sales.

Packwood Lake Hydroelectric Project
Total Operating Costs (Dollars in thousands)



Nuclear Project No. 1

Energy Northwest wholly owns Nuclear Project No. 1, a 1,250-MWe plant, which was placed in extended construction delay status in 1982, when it was 65% complete. On May 13, 1994, Energy Northwest's Board of Directors adopted a resolution terminating Nuclear Project No. 1. All funding requirements are net-billed obligations of Nuclear Project No. 1. Termination expenses and debt service costs comprise the activity of Nuclear Project No. 1 and are net-billed (See Notes 5 and 10).

Assets, Liabilities, and Net Position Analysis

Assets and deferred outflows decreased $21.4 million from $912.9 million in FY 2023 to $891.5 million in FY 2024. The change was due to a decrease of $22.0 million in costs in excess of billings, offset by a $0.5 million increase in current restricted assets from bond activity and a $0.1 million increase in unrestricted cash.

Total liabilities, net position, and deferred inflows decreased $21.4 million. Long-term debt decreased $7.3 million from $809.1 million in FY 2023 to $801.8 million in FY 2024 and there was a decrease related to debt discounts/premiums of $13.3 million. The overall change in long-term debt was due to debt activity associated with the planned and approved regional cooperation debt program. Total restricted liabilities increased $1.4 million from $19.6 million in FY 2023 to $21.0 million in FY 2024, which is an increase in total accrued interest payable on long-term debt (See Note 1). Current liabilities remained materially static for FY 2024 as compared to FY 2023. Total long-term liabilities increased $1.5 million, which consisted of an increase of $1.6 million to decommissioning liability for a total of $3.9 million for the asset retirement obligation per GASB No. 83 (See Note 9), offset by a $20 thousand decrease in pension liability per GASB No. 68 (See Note 6), and a $33 thousand decrease in long-term lease liability per GASB 87 (See Note 13). Deferred inflows decreased $3.6 million from $16.4 million in FY 2023 to $12.7 million in FY 2024. The changes are due to a decrease of $3.5 million in deferred inflows for unamortized gain on bond refunding and a $0.1 million decrease in deferred pension inflows recognized in accordance with GASB 68 (See Note 6). There were no major changes in the balance for deferred credit.

Revenue and Expenses Analysis

Other Income and Expenses showed a net increase to expenses of $4.8 million from $19.7 million in FY 2023 to $24.5 million in FY 2024. The change includes an increase to the decommissioning estimate of $2.6 million. The decommissioning change in estimate was per GASB No. 83 (See Note 9). Also, there was an increase on $2.2 million in bond related interest expense and amortization.

Nuclear Project No. 3

Nuclear Project No. 3, a 1,240-MWe plant, was placed in extended construction delay status in 1983, when it was 75% complete. On May 13, 1994, Energy Northwest's Board of Directors adopted a resolution terminating Nuclear Project No. 3. Energy Northwest is no longer responsible for any site restoration costs as they were transferred with the assets to the Satsop Redevelopment Project. The debt service-related activities remain the responsibility of Energy Northwest and are net-billed (See Notes 5 and 10).

Assets, Liabilities, and Net Position Analysis

Current assets decreased $1.2 million from $28.7 million in FY 2023 to $27.5 million in FY 2024, major driver was in cash. Cash decreased $1.5 million offset by an increase in current restricted assets of $0.3 million from $23.4 million in FY 2023 to $23.7 million in FY 2024 from bond activity. Other assets decreased $19.2 million from $1.0313 billion in FY 2023 to $1.0121 billion in FY 2024. The decrease was in costs in excess of billings related to the net effect of payment of current maturities and refunding activity associated with the regional cooperation debt program.

Long-term debt decreased $13.0 million from $950.7 million in FY 2023 to $937.7 million in FY 2024 and there was a decrease related to debt discounts/premiums on debt activity during the year of $10.1 million. The overall change in long-term debt was due to debt activity associated with the planned and approved regional cooperation debt program. Total restricted liabilities increased $0.6 million from $23.7 million in FY 2023 to $24.3 million in FY 2024, which is an increase in total accrued interest payable on long-term debt (See Note 1). Deferred inflows increased $2.1 million for unamortized gain on bond refunding. There were no significant changes in deferred credits.

Revenue and Expenses Analysis

Overall expenses and revenues increased by $0.6 million in FY 2024 due to increased interest expense and bond amortization costs.

Business Development Fund

Energy Northwest was created to enable Washington public power utilities and municipalities to build and operate generation projects. The Business Development Fund (BDF) was created by Executive Board Resolution No. 1006 in April 1997, for the purpose of holding, administering, disbursing, and accounting for Energy Northwest costs and revenues generated from engaging in new business opportunities.

The BDF is managed as an enterprise fund. Five business sectors have been created within the fund: Business Support, Energy & Professional Services, Laboratory Support, Nuclear

Development and Operation & Maintenance Services. A separate line of activity is used as general business unit support. Each line may have one or more programs that are managed as a unique business line activity.

Assets, Liabilities, and Net Position Analysis

Total assets and deferred outflows increased $9.7 million from $30.0 million in FY 2023 to $39.7 million in FY 2024. There was a net increase to Plant from FY 2023 to FY 2024 of $0.5 million. The increase to plant was offset by the period effect of depreciation of $0.8 million. There was an increase to current assets of $4.0 million, including a $3.7 million increase from cash and investment activities and a $0.3 million increase in receivables. Other assets increased $5.6 million for preliminary survey and engineering in the feasibility of building an advanced nuclear reactor on the land originally planned for Nuclear Project No. 1. Offsetting the increase is a decrease in deferred pension outflow of $0.4 million in accordance with GASB No. 68 and there was no change to the recognition of other postemployment benefit outflow in accordance with GASB No. 75 in FY 2024. Restricted assets stayed static in FY 2024 as compared to FY 2023.

Total liabilities, net position and deferred inflows increased $9.7 million. Current liabilities increased $2.8 million from FY 2023 due to timing of year-end outstanding items. Long-term liabilities decreased $0.4 million due to a $0.3 million decrease in net pension liability in accordance with GASB No. 68. Deferred inflows decreased $1.3 million in net pension liability. The increased change in net position of $8.6 million is the net of $2.4 million from operations in FY 2024 reflected in the activities described below, continuing margin achievement on business sector activity, $0.5 million in contributed capital from the electric vehicle projects, $0.1 million in contributed capital from Alternative Fuel Vehicle Refueling Property Credit under the Inflation Reduction Act, $0.1 million in contributed capital from demand reduction voltage initiatives, and $5.5 million in contributed capital from third party entities towards a feasibility study for an advanced nuclear reactor (See Note 1).

Revenue and Expenses Analysis

Operating revenues in FY 2024 remained relatively steady totaling $12.67 million as compared to FY 2023 revenues of $12.62 million. Various projects and timing of work were drivers for the overall revenue in the BDF and the five business sectors.

- The Business Support sector revenues remained relatively steady in FY 2024, with a slight increase from $53 thousand in FY 2023 to $54 thousand in FY 2024. The sector remains steady based on continued rental agreements.

- The Energy & Professional Services sector revenues decreased $0.6 million in FY 2024 from $2.1 million in FY 2023 to $1.5 million. The decrease in this sector was a result of reduced activities in electrical vehicle charging station initiatives that were not funded by grants in FY 2024 as compared to FY 2023. The revenues for grant funded electrical vehicle charging stations are included in other income/expense and contributed capital.

- The Laboratory Support sector increased $0.6 million in FY 2024 from $7.1 million in FY 2023 to $7.7 million. The increase in revenue is a result of the Calibration and Environmental Laboratories receiving additional work from existing customers and new customers.

- The Nuclear Development sector focus in FY 2024 was primarily on the feasibility study for an advanced nuclear reactor and the funding is reported in contributed capital (See Note 1). Thus, this sector did not contribute to the BDF operating revenues in FY 2024.

- The Operations & Maintenance sector supports public power in the areas of operations and maintenance of generating facilities and electric utility automation. Revenues from the Operations & Maintenance business sector remained steady at $3.4 million in FY 2024.

Operating costs increased $1.3 million from $15.0 million in FY 2023 to $16.3 million in FY 2024, which was a 8.7% increase in overall operating costs. The operating costs increase included a $1.5 million increase in administration and general expenses from indirect expenses from $17 thousand in FY 2023 to $1.5 million in FY 2024 and there was a $0.3 million increase in depreciation expense from $0.9 million in FY 2023 to $1.2 million in FY 2024. Offsetting the increase was a decrease in operations and maintenance of $0.5 million from $14.1 million in FY 2023 to $13.6 million in FY 2024.

Other Income and Expenses increased $1.8 million in FY 2024 to a net income of $6.0 million. There was a $1.5 million increase in non-operating grant revenue due primarily to grants received for the electric vehicle charging station initiatives offset by a reduction in the support of Terra Power's ARDP initiative. There was a $0.3 million increase in investment income.

In FY 2024 there is a $4.3 million increase to capital contributions related to multiple grants, property tax credit, and third party contributions related to the advanced nuclear reactor feasibility study. (See Note 1).

Nine Canyon Wind Project

The Nine Canyon Wind Project (Nine Canyon) is wholly owned and operated by Energy Northwest. Nine Canyon is located in the Horse Heaven Hills area southwest of Kennewick, Washington. Electricity generated by Nine Canyon is purchased by Pacific Northwest Public Utility Districts (purchasers). Each of the purchasers of Phase I, Phase II, and Phase III have signed a power purchase agreement which are part of the 2nd Amended and Restated Nine Canyon Wind Project Power Purchase Agreement which now has an end date of 2030. Nine Canyon is connected to the BPA transmission grid via a substation and transmission lines constructed by Benton County Public Utility District.

Phase I of Nine Canyon, which began commercial operation in September 2002, consists of 37 wind turbines, each with a maximum generating capacity of approximately 1.3 MW, for an aggregate generating capacity of 48.1 MW. Phase II of Nine Canyon, which was declared operational in December 2003, includes 12 wind turbines, each with a maximum generating capacity of 1.3 MW, for an aggregate generating capacity of approximately 15.6 MW. Phase III of Nine Canyon, which was declared operational in May 2008, includes 14 wind turbines, each with a maximum generating capacity of 2.3 MW, for an aggregate generating capacity of 32.2 MW. The total Nine Canyon generating capability is 95.9 MW, enough energy for approximately 39,000 average homes.

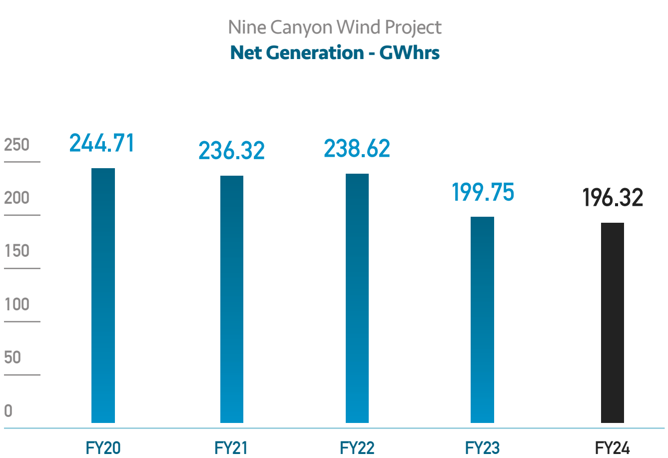
Nine Canyon produced 196.32 GWh of electricity in FY 2024 versus 199.75 GWh in FY 2023. The decrease of 1.7% for generation was a direct result of a decreased average monthly capacity factor of 24.0% for FY 2024 versus 24.1% for FY 2023 (decrease of 0.4%); however, average wind speed remained steady at 14.99 miles per hour for both FY 2024 and FY 2023. Gross Generation for FY 2024 and FY 2023 have been below the five-year average gross generation for the project.

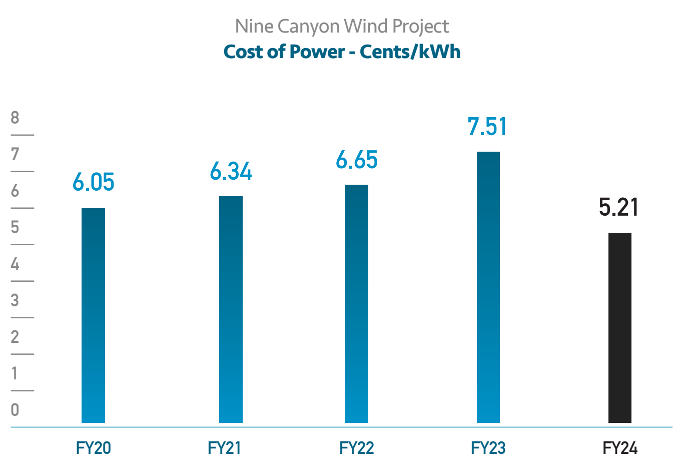
Nine Canyon's cost performance is measured by the cost of power indicator. The cost of power for FY 2024 was 5.21 cents per kWh as compared to 7.51 cents per kWh in FY 2023. The cost of power fluctuates year to year depending on various factors such as wind conditions and unplanned maintenance and is distinctly different than revenue billed cost of power discussed in the revenue and expense analysis section. The cost of power does not include the Bonneville Power Administration's (BPA) Transmission costs, which are pass-through costs to the purchasers. The decrease of 30.6% in cost of power for FY 2024 was attributable to decreased operating and fixed costs, which will be discussed in the revenue and expenses analysis section, but was offset by the slight reduction in generation discussed above.

Assets, Liabilities, and Net Position Analysis

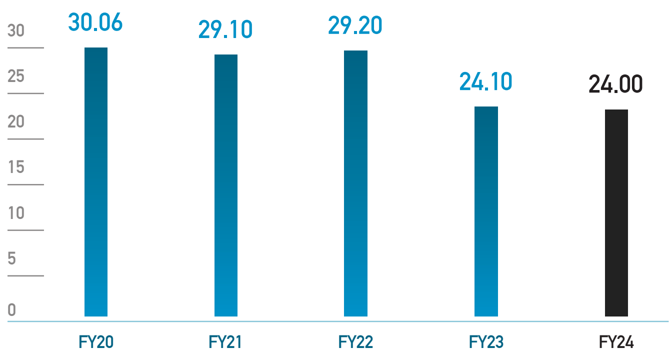
Total assets and deferred outflows decreased $5.9 million from $57.2 million in FY 2023 to $51.3 million in FY 2024. There was a decrease of $3.2 million in net plant due to accumulated depreciation. There was a decrease of current assets of $6.1 million, which includes a $6.5 million decrease in current restricted assets, and a decrease of $0.2 million in receivables offset by an increase of $0.4 million in the timing of cash and investment activities and an increase of $0.2 million in due from other business units. There was an increase to non-current restricted funds of $3.9 million related to debt service funds. Unamortized debt expense decreased $0.1 million, and a decrease to deferred outflows related to the asset retirement obligation of $0.4 million due to the requirements of GASB No. 83 (See Note 9).

There was an overall decrease to liabilities, net position, and deferred inflows of $5.9 million. Changes were a decrease to long-term debt (including unamortized bond discount/premium) of $4.4 million to $29.5 million for FY 2024, a decrease to current maturities of debt of $6.3 million, a decrease of $0.2 million to accounts payable and accrued expenses, and a decrease of $0.2 million accrued debt service interest. Other long-term liability changes were a decrease of $0.1 million for pension liability, and an increase of $0.7 million to the decommissioning liability, as

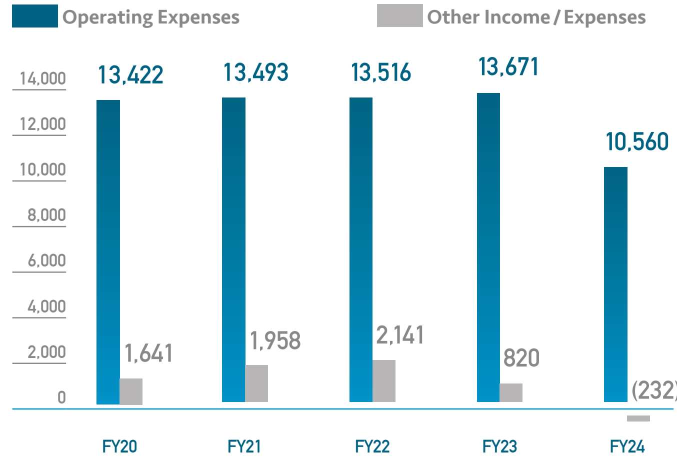




Nine Canyon Wind Project
Capacity Factor (%)



Nine Canyon Wind Project
Total Operating Costs (Dollars in thousands)



a result of indexing requirements in accordance with GASB No. 83 (See Note 9). There was a $0.2 million decrease to the deferred pension inflow. Pension liability and deferrals are recognized in accordance with GASB No. 68 (See Note 6). The change in net position of $4.8 million is the net of the total from net operations of $4.6 million in FY 2024, and a $0.2 million net of investment income and interest expense and debt amortization. Although a decrease in the year-to-year operations, FY 2024 positive results continue to reflect the results of the debt financing efforts and cost reduction/ stabilization efforts.

In previous years Energy Northwest has accrued, as income (contribution) from the Department of Energy, Renewable Energy Production Incentive (REPI) payments that enable Nine Canyon to receive funds based on generation as it applies to the REPI legislation. REPI was created to promote increases in the generation and utilization of electricity from renewable energy sources and to further the advances of renewable energy technologies. This program, authorized under Section 1212 of the Energy Policy Act of 1992, provides financial incentive payments for electricity produced and sold by new qualifying renewable energy generation facilities. The payment stream from Nine Canyon participants and the REPI receipts was projected to cover the total costs over the purchase agreement. Continued shortfalls in REPI funding for the Nine Canyon project led to a revised rate plan to incorporate the impact of this shortfall over the life of the project (2030 proposed end date) in FY 2008. Results of operations, debt refunding, and generation affect the yearly rate plan. In FY 2017 Nine Canyon Participants of all three phases realized a 3% decrease in rates driven by debt refinancing efforts and cost reduction/stabilization efforts. The current rate plan remains in effect; going forward the increase or decrease in rates will be based on cash requirements of debt repayment and the cost of operations.

Revenues and Expenses Analysis

Operating revenues in FY 2024 totaled $15.2 million as compared to FY 2023 revenues of $15.3 million, a decrease of $0.1 million (0.7%). The slight decrease in revenues is due to reduced billings to participants based on lower costs. The project received revenue from the billing of the purchasers at an average rate of $75.81 per MWh for FY 2024 as compared to $78.15 per MWh for FY 2023. The decrease in the billed rates reflects the lower operating costs. The stabilization of revenue continues to reflect the implementation of the current rate plan account for costs of operations over the remaining life of the project, taking into account the REPI shortfalls in the early years of the project.

Operating expenses decreased $3.1 million in FY 2024 to $10.6 million. There was a decrease in depreciation and amortization of $3.5 million due to the Phase I and II turbines being fully depreciated at the end of FY 2023, and a decrease in administrative and general costs of $0.2 million. The decreases were offset by increases in decommissioning expense of $0.1 million due to annual indexing requirements of the obligation related to GASB No. 83 (See Note 9). Also, there was a $0.5 million increase in operations and maintenance. Other income and expenses decreased $1.0 million from $0.8 million in net expenses in FY 2023 to net income of $0.2 million in FY 2024. Bond interest expense and changes in amortized bond expenses decreased $0.3 million and investment income increased $0.7 million, resulting in a net $1.0 million income. Net income or change in net position of $4.8 million for FY 2024 was due to the slight reduction in operating revenues, reducing operating expenses and net increase in investment income.

The original plan anticipated operating at a loss in the early years and gradually increasing the rate charged to the purchasers to avoid a large rate increase after the REPI expires. The REPI incentive expires 10 years from the initial operation startup date for each phase. Reserves that were established are used to facilitate this plan. The rate plan in FY 2008 was revised to account for the shortfall experienced in the REPI funding and to provide a new rate scenario out to the 2030 project end date. Energy Northwest did not receive REPI funding in FY 2024 and is not anticipating receiving any future REPI incentives. The rate plan was revised In FY 2017 to reflect positive cash requirement coverage and remains in effect. Future rate adjustments may be necessary to cover the estimated costs incurred for the eventual decommissioning of the Nine Canyon Project.

Internal Service Fund

The Internal Service Fund (ISF) (formerly the General Fund) was established in May 1957. The ISF provides services to the other funds. This fund accounts for the central procurement of certain common goods and services for the business units on a cost reimbursement basis. (See Note 1).

Assets, Liabilities, and Net Position Analysis

Total assets and deferred outflows increased $1.9 million from $43.5 million in FY 2023 to $45.4 million in FY 2024. There was an increase in net plant in service of $3.3 million, mostly related to purchases of data processing equipment and new SBITA assets recognized in accordance with GASB 96 (See Note 14). Remaining major changes were a decrease to current cash and investments of $0.9 million, a $0.3 million decrease in due from other business units, a $0.4 million decrease in prepaid assets and a $0.2 increase in non-current restricted assets.

The total net liabilities, net position and deferred inflows increased $1.9 million. The increase is due to an increase in accounts payable and accrued expenses of $10.4 million, and an increase in long term SBITA liability of $2.4 million offset by a decrease in due to other units of $10.9 million.

Revenues and Expenses Analysis

Overall results of operations held steady for FY 2024.

Current Debt Ratings

(Unaudited)

Energy Northwest (Long-Term)	Net-Billed Rating	Nine Canyon Rating
Fitch, Inc.	AA	A
Moodys Investors Service, Inc. (Moodys)	Aa1	A1
Standard and Poor's Ratings Services (S & P)	AA-	NR

Statement of Net Position As of June 30, 2024 (Dollars in thousands)

	Columbia Generating Station	Packwood Lake Hydroelectric Project	Nuclear Project No. 1	Nuclear Project No. 3	Business Development Fund	Nine Canyon Wind Project	Internal Service Fund	2024 Combined Total
ASSETS								
CURRENT ASSETS								
Cash	$ 68,934	$ 62	$ 3,560	$ 3,617	$ 8,160	$ 14,403	$ 15,994	$ 114,730
Investments	-	808	-	-	6,268	-	10,073	17,149
Accounts and other receivables	20,274	198	-	-	2,789	84	113	23,458
Due from other business units	-	101	120	143	-	474	(838)	-
Materials and supplies	184,546	-	-	-	3	-	-	184,549
Prepayments and other	3,822	16	5	5	66	38	968	4,920
Current restricted assets	226,364	-	20,129	23,702	-	4,662	-	274,857
TOTAL CURRENT ASSETS	503,940	1,185	23,814	27,467	17,286	19,661	26,310	619,663
NON CURRENT ASSETS								
UTILITY PLANT (NOTE 2)								
In service	4,999,843	23,648	-	-	18,057	133,836	58,948	5,234,332
In service - leases and subscriptions	6,694	75	1,458	-	135	836	7,616	16,814
Not in service								
Construction work in progress	166,348	-	-	-	-	-	-	166,348
Accumulated depreciation	(3,473,178)	(14,747)	-	-	(6,192)	(124,720)	(45,108)	(3,663,945)
Accumulated amortization - leases and subscriptions	(2,635)	(6)	(136)	-	(17)	(95)	(3,682)	(6,571)
Net utility plant	1,697,072	8,970	1,322	-	11,983	9,857	17,774	1,746,978
Nuclear fuel, net of accumulated amortization	406,306	-	-	-	-	-	-	406,306
Long term lease receivables	3,045	-	-	-	449	-	-	3,494
Pension asset restricted	42,709	224	134	-	1,666	457	-	45,190
Other non current restricted assets	291,865	-	-	-	-	13,140	1,349	306,354
TOTAL NONCURRENT ASSETS	2,440,997	9,194	1,456	-	14,098	23,454	19,123	2,508,322
OTHER ASSETS								
Cost in excess of billings	2,014,081	-	866,006	1,012,085	-	-	-	3,892,172
Preliminary Survey and Investigation	-	-	-	-	5,578	-	-	5,578
TOTAL OTHER ASSETS	2,014,081	-	866,006	1,012,085	5,578	-	-	3,897,750
TOTAL ASSETS	4,959,018	10,379	891,276	1,039,552	36,962	43,115	45,433	7,025,735
DEFERRED OUTFLOWS OF RESOURCES								
Unamortized loss on bond refunding	1,085	-	1	-	-	345	-	1,431
Pension	43,670	198	203	-	2,634	417	-	47,122
OPEB	1,241	6	5	-	69	12	-	1,333
Decommissioning	885,979	-	-	-	41	7,397	-	893,417
TOTAL DEFERRED OUTFLOWS OF RESOURCES	931,975	204	209	-	2,744	8,171	-	943,303
TOTAL ASSETS AND DEFERRED OUTFLOWS	$ 5,890,993	$ 10,583	$ 891,485	$ 1,039,552	$ 39,706	$ 51,286	$ 45,433	$ 7,969,038

The accompanying notes are an integral part of these combined financial statements

Statement of Net Position As of June 30, 2024 (Dollars in thousands)

	Columbia Generating Station	Packwood Lake Hydroelectric Project	Nuclear Project No. 1	Nuclear Project No. 3	Business Development Fund	Nine Canyon Wind Project	Internal Service Fund	2024 Combined Total
LIABILITIES AND NET POSITION								
CURRENT LIABILITIES								
Current maturities of long-term debt	$ 150,645	$ -	$ -	$ -	$ -	$ 3,960	$ -	$ 154,605
Accounts payable and accrued expenses	49,578	121	490	10	3,637	407	59,929	114,172
Due to participants	22,836	607	-	-	-	-	-	23,443
Due to other business units	16,321	-	-	-	673	-	(16,994)	-
TOTAL CURRENT LIABILITIES	239,380	728	490	10	4,310	4,367	42,935	292,220
LIABILITIES-PAYABLE FROM RESTRICTED ASSETS (NOTE 1)								
Debt service funds								
Accrued interest payable	78,191	-	21,008	24,269	-	702	-	124,170
TOTAL RESTRICTED LIABILITIES	78,191	-	21,008	24,269	-	702	-	124,170
LONG-TERM DEBT (NOTE 5)								
Revenue bonds payable	3,143,000	-	801,805	937,700	-	28,005	-	4,910,510
Unamortized (discount)/premium on bonds - net	442,731	-	49,849	74,848	-	1,466	-	568,894
TOTAL LONG-TERM DEBT	3,585,731	-	851,654	1,012,548	-	29,471	-	5,479,404
OTHER LONG-TERM LIABILITIES								
Pension liability	18,081	81	86	-	1,082	172	-	19,502
OPEB liability	23,202	112	104	-	827	208	-	24,453
Decommissioning liability	1,886,967	-	3,939	-	47	22,213	-	1,913,166
Long term leases and subscriptions liability	3,229	53	1,298	-	116	727	2,498	7,921
Other	105	-	-	-	-	-	-	105
TOTAL OTHER LONG-TERM LIABILITIES	1,931,584	246	5,427	-	2,072	23,320	2,498	1,965,147
OTHER LIABILITIES								
Advances from members and others	-	9,557	-	-	-	-	-	9,557
Other	175	-	168	168	-	-	-	511
TOTAL OTHER LIABILITIES	175	9,557	168	168	-	-	-	10,068
TOTAL LIABILITIES	5,835,061	10,531	878,747	1,036,995	6,382	57,860	45,433	7,871,009
DEFERRED INFLOWS OF RESOURCES								
Unamortized gain on bond refunding	21,054	-	12,753	2,557	-	-	-	36,364
Pension	27,435	36	(33)	-	(724)	245	-	26,959
OPEB	3,694	16	18	-	240	35	-	4,003
Lease	3,749	-	-	-	450	-	-	4,199
TOTAL DEFERRED INFLOWS OF RESOURCES	55,932	52	12,738	2,557	(34)	280	-	71,525
NET POSITION								
Net investment in capital assets	-	-	-	-	17,445	(16,700)	-	745
Restricted for decommissioning	-	-	-	-	-	6,612	-	6,612
Restricted for debt service	-	-	-	-	-	3,959	-	3,959
Restricted for pension asset	-	-	-	-	1,666	457	-	2,123
Unrestricted	-	-	-	-	14,247	(1,182)	-	13,065
NET POSITION	-	-	-	-	33,358	(6,854)	-	26,504
TOTAL LIABILITIES, NET POSITION, AND DEFERRED INFLOWS	$ 5,890,993	$ 10,583	$ 891,485	$ 1,039,552	$ 39,706	$ 51,286	$ 45,433	$ 7,969,038

The accompanying notes are an integral part of these combined financial statements

Statements of Revenues, Expenses, and Changes in Net Position As of June 30, 2024 (Dollars in thousands)

	Columbia Generating Station	Packwood Lake Hydroelectric Project	Nuclear Project No. 1	Nuclear Project No. 3	Business Development Fund	Nine Canyon Wind Project	Internal Service Fund	2024 Combined Total
OPERATING REVENUES								
Operating revenues	$ 510,991	$ 3,018	$ -	$ -	$ 12,647	$ 15,190	$ -	$ 541,846
Lease revenues	-	-	-	-	19	-	-	19
Total operating revenues	510,991	3,018	-	-	12,666	15,190	-	541,865
OPERATING EXPENSES								
Nuclear fuel, net	60,497	-	-	-	-	-	-	60,497
Decommissioning	42,344	-	-	-	2	1,115	-	43,461
Depreciation and amortization	105,939	371	-	-	1,167	3,319	-	110,796
Operations and maintenance	129,862	2,822	-	-	13,636	6,344	-	152,664
Administrative & general	78,608	(120)	-	-	1,482	(260)	-	79,710
Generation tax	4,435	14	-	-	-	42	-	4,491
Total operating expenses	421,685	3,087	-	-	16,287	10,560	-	451,619
OPERATING INCOME (LOSS)	89,306	(69)	-	-	(3,621)	4,630	-	90,246
OTHER INCOME & EXPENSE								
Other	2,424	16	23,216	27,825	16	15	-	53,512
Other lease revenue	826	-	-	-	-	-	-	826
Grant revenue non operating	-	-	-	-	5,501	-	-	5,501
Gain on DOE settlement	15,037	-	-	-	-	-	-	15,037
Investment income/(loss)	10,725	54	1,321	1,018	505	1,300	-	14,923
Interest expense and debt amortization	(118,323)	(1)	(21,406)	(28,526)	(8)	(1,083)	-	(169,347)
Plant preservation and termination costs	-	-	(571)	(317)	-	-	-	(888)
Depreciation and amortization	-	-	(53)	-	-	-	-	(53)
Decommissioning	-	-	(2,507)	-	-	-	-	(2,507)
TOTAL OTHER INCOME & EXPENSE	(89,311)	69	-	-	6,014	232	-	(82,996)
NET INCOME (LOSS) BEFORE CONTRIBUTIONS	(5)	-	-	-	2,393	4,862	-	7,250
CAPITAL CONTRIBUTIONS	5	-	-	-	6,235	-	-	6,240
NET INCOME (LOSS) AFTER CONTRIBUTIONS	-	-	-	-	8,628	4,862	-	13,490
TOTAL NET POSITION, BEGINNING OF YEAR	-	-	-	-	24,730	(11,716)	-	13,014
TOTAL NET POSITION, END OF YEAR	$ -	$ -	$ -	$ -	$ 33,358	$ (6,854)	$ -	$ 26,504

The accompanying notes are an integral part of these combined financial statements

Statements of Cash Flows As of June 30, 2024 (Dollars in thousands)

	Columbia Generating Station	Packwood Lake Hydroelectric Project	Nuclear Project No. 1	Nuclear Project No. 3	Business Development Fund	Nine Canyon Wind Project	Internal Service Fund	2024 Combined Total
CASH FLOWS FROM OPERATING ACTIVITIES								
Operating revenue receipts	$ 599,707	$ 3,458	$ -	$ -	$ 10,085	$ 15,368	$ -	$ 628,618
Cash payments for operating expenses	(266,530)	(2,898)	-	-	(16,915)	(6,935)	-	(293,278)
DOE Cash settlement	21,134	-	-	-	-	-	-	21,134
Cash payments for services net of cash received from other units	-	-	-	-	-	-	(1,722)	(1,722)
Net cash provided/(used) by operating activities	354,311	560	-	-	(6,830)	8,433	(1,722)	354,752
CASH FLOWS FROM CAPITAL AND RELATED FINANCING ACTIVITIES								
Proceeds from bond refundings	224,495	-	930	665	-	-	-	226,090
Principal paid on revenue bond maturities	(45,220)	-	-	-	-	(10,255)	-	(55,475)
Payment for bond issuance and financing costs	(3,134)	(10)	(1,124)	(897)	(26)	(18)	-	(5,209)
Interest paid on bonds	(146,437)	-	(40,407)	(47,975)	-	(1,660)	-	(236,479)
Interest paid on leases	(203)	-	(35)	-	(8)	(20)	-	(266)
Payment for capital items	(104,378)	(884)	-	-	(1,440)	(29)	(5,928)	(112,659)
Reimbursement for capital items	-	-	-	-	5,488	-	5,726	11,214
Cash received from sale of assets	45	-	-	-	-	-	-	45
Capital grant received	5	-	-	-	532	-	-	537
Operating revenue receipts - lease	-	-	-	-	26	-	-	26
Non operating revenue receipts - lease	908	-	-	-	-	-	-	908
Nuclear fuel acquisitions	(35,712)	-	-	-	-	-	-	(35,712)
Payments received from BPA for terminated nuclear projects	-	-	39,992	45,989	-	-	-	85,981
Net cash provided/(used) by capital and related financing activities	(109,631)	(894)	(644)	(2,218)	4,572	(11,982)	(202)	(120,999)
CASH FLOWS FROM NON-CAPITAL FINANCING ACTIVITIES								
Payment for notes payable	(26,850)	-	-	-	-	-	-	(26,850)
Interest paid on notes	(390)	-	(20)	(20)	-	-	-	(430)
Grant received non operating	-	-	-	-	5,468	-	-	5,468
Net cash provided/(used) by non-capital finance activities	(27,240)	-	(20)	(20)	5,468	-	-	(21,812)
CASH FLOWS FROM INVESTING ACTIVITIES								
Purchases of investment securities	(296,582)	(786)	(4,399)	(7,601)	(7,250)	(24,533)	(14,695)	(355,846)
Sales of investment securities	196,810	537	4,481	7,757	4,103	28,459	23,866	266,013
Interest on investments	5,179	19	1,238	862	205	186	150	7,839
Net cash provided/(used) by investing activities	(94,593)	(230)	1,320	1,018	(2,942)	4,112	9,321	(81,994)
NET INCREASE(DECREASE) IN CASH	122,847	(564)	656	(1,220)	268	563	7,397	129,947
CASH AT JUNE 30, 2023	211,583	626	23,033	28,539	7,892	18,840	8,647	299,160
CASH AT JUNE 30, 2024 (NOTE H)	$ 334,430	$ 62	$ 23,689	$ 27,319	$ 8,160	$ 19,403	$ 16,044	$ 429,107

The accompanying notes are an integral part of these combined financial statements

Statements of Cash Flows (continued) As of June 30, 2024 (Dollars in thousands)

	Columbia Generating Station	Packwood Lake Hydroelectric Project	Nuclear Project No. 1	Nuclear Project No. 3	Business Development Fund	Nine Canyon Wind Project	Internal Service Fund	2024 Combined Total
Reconciliation of Direct Cash Flow to Statement of Net Position								
Current cash unrestricted	$ 68,934	$ 62	$ 3,560	$ 3,617	$ 8,160	$ 14,403	$ 15,994	$ 114,730
Current cash restricted debt service funds	226,364	-	20,129	23,702	-	4,662	-	274,857
Current unrestricted non cash equivalents	-	808	-	-	6,272	1	10,079	17,160
Non current restricted cash special funds	-	-	-	-	-	-	50	50
Non current restricted cash debt service funds	39,132	-	-	-	-	338	-	39,470
Non current restricted non cash equivalents	252,733	-	-	-	-	12,801	1,299	266,833
Total Cash and non cash equivalents	$ 587,163	$ 870	$ 23,689	$ 27,319	$ 14,432	$ 32,205	$ 27,422	$ 713,100
less non cash equivalents	252,733	808	-	-	6,272	12,802	11,378	283,993
Total Statement of Net Position Cash	$ 334,430	$ 62	$ 23,689	$ 27,319	$ 8,160	$ 19,403	$ 16,044	$ 429,107
RECONCILIATION OF NET OPERATING REVENUES TO NET CASH FLOWS PROVIDED BY OPERATING ACTIVITIES								
Net income/loss from operations	$ 89,306	$ (69)	$ -	$ -	$ (3,621)	$ 4,630	$ -	$ 90,246
Adjustments to reconcile net operating revenues to cash provided by operating activities:								
Depreciation and amortization	159,853	360	-	-	1,162	3,288	-	164,663
Decommissioning	42,344	-	-	-	2	1,115	-	43,461
Non-operating revenues	-	(17)	-	-	-	(15)	-	(32)
Non-operating Grant Revenues	-	-	-	-	(5,501)	-	-	(5,501)
Other	(6,848)	(71)	-	-	17,020	127	(2,486)	7,742
Change in operating assets and liabilities:								
Costs in excess of billings	78,210	511	-	-	-	-	-	78,721
Accounts receivable	25,745	4	-	-	(6,271)	(34)	(178)	19,266
Materials and supplies	(12,959)	-	-	-	(3)	-	-	(12,962)
Prepaid and other assets	(672)	15	-	-	(5,589)	(2)	386	(5,862)
Due from/to other business units	10,805	(63)	-	-	127	(254)	(10,626)	(11)
Change in net pension liability, OPEB Liability, and deferrals	(20,443)	(101)	-	-	(1,276)	(211)	-	(22,031)
Leases	(729)	(10)	-	-	(24)	29	(1,667)	(2,401)
Accounts payable	(10,301)	1	-	-	2,632	(240)	12,849	4,941
Net cash provided/(used) by operating activities	$ 354,311	$ 560	$ -	$ -	$ (1,342)	$ 8,433	$ (1,722)	$ 360,240
Non-cash activities								
Bond refunding	$ 377,893	$ -	$ 201,649	$ 137,205	$ -	$ -	$ -	$ 716,747
Decommissioning liability adjustment	$ 136,189	$ -	$ 1,578	$ -	$ 1	$ 710	$ -	$ 138,478
Market Adjustments on Investments	$ 5,545	$ 35	$ 83	$ 156	$ 300	$ 1,114	$ (213)	$ 7,020

The accompanying notes are an integral part of these combined financial statements

Notes To Financial Statements

NOTE 1 - Summary of Operations and Significant Accounting Policies

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

Membership consists of 24 public utility districts and 5 municipalities. All members own and operate electric systems within the state of Washington.

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

Energy Northwest maintains seven business units. Each unit is financed and accounted for separately from all other current or future business units and is accounted for as a major fund for governmental accounting purposes.

All electrical energy produced by Energy Northwest's net-billed business units is ultimately delivered to electrical distribution facilities owned and operated by Bonneville Power Administration (BPA) as part of the Federal Columbia River Power System. BPA in turn distributes the electricity to electric utility systems throughout the Northwest, including participants in Energy Northwest's business units, for ultimate distribution to consumers. Participants in Energy Northwest's net-billed business units consist of public utilities and rural electric cooperatives located in the western United States who have entered into net-billing agreements with Energy Northwest and BPA for participation in one or more of Energy Northwest's business units. BPA is obligated by law to establish rates for electric power which will recover the cost of electric energy acquired from Energy Northwest and other sources, as well as BPA's other costs (See Note 5).

Energy Northwest operates the Columbia Generating Station (Columbia), a 1,174-MWe (Design Electric Rating, net) generating plant completed in 1984. Energy Northwest has obtained all permits and licenses required to operate Columbia. Columbia was issued a standard 40-year operating license by the Nuclear Regulatory Commission (NRC) in 1983. On January 19, 2010 Energy Northwest submitted an application to the NRC to renew the license for an additional 20 years, thus continuing operations to 2043. A renewal license was granted by the NRC on May 22, 2012 for continued operation of Columbia to December 31, 2043. Columbia is a net-billed project (see Note 5).

Energy Northwest also operates the Packwood Lake Hydroelectric Project (Packwood), a 27.5-MWe generating plant completed in 1964. Packwood has been operating under a 50-year license issued by the Federal Energy Regulatory Commission (FERC), which expired on February 28, 2010. Energy Northwest submitted the Final License Application (FLA) for renewal of the operating license to FERC on February 22, 2008. On October 11, 2018, FERC issued forty-year operating license effective October 1, 2018, and will expire on September 30, 2058.

The electric power produced by Packwood is sold to 12 project participant utilities which pay the costs of Packwood. The Packwood participants are obligated to pay annual costs of Packwood including debt service, whether or not Packwood is operable. The participants also share Packwood revenue. Packwood is a net-billed project (see Note 5).

Nuclear Project No. 1, a 1,250-MWe plant, was placed in extended construction delay status in 1982, when it was 65 percent complete. Nuclear Project No. 3, a 1,240-MWe plant, was placed in extended construction delay status in 1983, when it was 75 percent complete. On May 13, 1994, Energy Northwest's Board of Directors adopted resolutions terminating Nuclear Projects Nos. 1 and 3. All funding requirements remain as net-billed obligations of Nuclear Projects Nos. 1 and 3. Energy Northwest is no longer responsible for site restoration costs for Nuclear Project No. 3. (See Note 10)

The Business Development Fund (BDF) was established in April 1997 to pursue and develop new energy related business opportunities. There are five main business lines associated with this business unit: Business Support, Energy & Professional Services, Laboratory Support, Nuclear Development and Operation & Maintenance Services. The BDF is not a net-billed project, all excess revenues received from operations are kept within the BDF to further its mission of developing new energy related business opportunities.

The Nine Canyon Wind Project (Nine Canyon) was established in January 2001 for the purpose of exploring and establishing a wind energy project. Phase I of the project was completed in fiscal year 2003 and Phase II was completed in fiscal year 2004. Phase I and II combined capacity is approximately 63.7 MWe. Phase III was completed in fiscal year 2008 adding an additional 14 wind turbines to Nine Canyon and adding an aggregate capacity of 32.2 MWe. The total number of turbines at Nine Canyon is 63 and the total capacity is 95.9 MWe.

The electric power produced by Nine Canyon is sold to 10 project participant utilities based on an agreed upon billing amount, whether or not Nine Canyon is operating, which is adjusted prior to each fiscal year. The original plan for Nine Canyon was for the participants to pay a lower billing rate in the first years of the project and the difference between the billings and costs was planned to be covered by the Department of Energy, Renewable Energy Production Incentive (REPI) payments. In FY 2008, a revised billing rate plan was established to address shortfalls in REPI payments, which would allow the shortfalls to be recovered over the life of the project, which is currently projected in FY 2030. The current billings to the participants covers the annual costs of Nine Canyon, including debt service and payments to a decommissioning trust fund (see Note 9.)

The Internal Service Fund was established in May 1957. It is currently used to account for the central procurement of certain common goods and services for the business units on a cost reimbursement basis and is not a net-billed project.

Energy Northwest's fiscal year (FY) begins on July 1 and ends on June 30.

The following is a summary of the significant accounting policies:

A) Basis of Accounting and Presentation: The accounting policies of Energy Northwest conform to Generally Accepted Accounting Principles (GAAP) applicable to governmental units. The Governmental Accounting Standards Board (GASB) is the accepted standard-setting body for establishing governmental accounting and financial reporting principles this includes all GASB implementation guides, GASB technical Bulletins, and guidance from the American Institute of Certified Public Accountants (AICPA) that is cleared by GASB. The accounting and reporting policies of Energy Northwest are regulated by the Washington State Auditor's Office and are based on the Uniform System of Accounts prescribed for public utilities and licensees by FERC. Energy Northwest uses an accrual basis of accounting where revenues are recognized when earned and expenses are recognized when incurred. Revenues and expenses related to Energy Northwest's operations are considered to be operating revenues and expenses; while revenues and expenses related to capital, financing and investing activities are considered to be other income and expenses. Separate funds and books of accounts are maintained for each business unit. Payment of the obligations of one business unit with funds of another business unit is prohibited and would constitute violation of bond resolution covenants (See Note 4).

Energy Northwest maintains an Internal Service Fund for centralized control and accounting of certain capital assets such as data processing equipment, and for payment and accounting of internal services, payroll, benefits, administrative and general expenses, and certain contracted services on a cost reimbursement basis. Certain assets in the Internal Service Fund are also owned by this Fund and operated for the benefit of other projects. Depreciation relating to capital assets is charged to the appropriate business units based upon assets held by each project.

Liabilities of the Internal Service Fund represent accrued payroll, vacation pay, employee benefits, such as pensions and other post-retirement benefits, and common accounts payable which have been charged directly or indirectly to business units and will be funded by the business units when paid. Net amounts owed to, or from, Energy Northwest business units are recorded as Current Liabilities–Due to other business units, or as Current Assets–Due from other business units on the Internal Service Fund Statement of Net Position.

The combined total column on the financial statements is for presentation only as each Energy Northwest business unit is financed and accounted for separately from all other current and future business units.

Issued but not Adopted Guidance:

GASB Statement No. 101, Compensated Absences. The objective of this Statement is to better meet the information needs of financial statement users by updating the recognition and measurement guidance for compensated absences. That objective is achieved by aligning the recognition and measurement guidance under a unified model and by amending certain previously required disclosures. This statement is effective for Energy Northwest in FY 2025. Energy Northwest is currently evaluating the impact of the statement.

GASB Statement No. 102, Certain Risk Disclosures. The objective of this Statement is to provide users of government financial statements with essential information about risks related to government's vulnerabilities due to certain concentrations or constraints. This statement is effective for Energy Northwest in FY 2025. Energy Northwest is currently evaluating the impact of the statement.

GASB Statement No. 103, Financial Reporting Model Improvements. The objective of this Statement is to improve key components of the financial reporting model to enhance its effectiveness in providing information that is essential for decision making and assessing a government's accountability. This statement is effective for Energy Northwest in FY 2026. Energy Northwest is currently evaluating the impact of the statement.

B) Utility Plant and Depreciation: Utility plant is recorded at original cost which includes both direct costs of construction or acquisition and indirect costs.

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

Buildings and Improvements	20 - 60 years
Generation Plant	40 years
Transportation Equipment	6 - 10 years
General Plant and Equipment	5 - 15 years

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

The utility plant and net position of Nuclear Projects Nos. 1 and 3 have been reduced to their estimated net realizable values due to termination. A write-down of Nuclear Projects Nos. 1 and 3 was recorded in FY 1995 and included in Cost in Excess of Billings. Interest expense, termination expenses and asset disposition costs for Nuclear Projects Nos. 1 and 3 have been charged to other non-operating income and expense (See Note 10).

Projects are generally capitalized if they are over $50 thousand and meet the improvement or extension criteria set forth in Energy Northwest's capitalization policy.

C) Capital Contributions: Energy Northwest is involved in various grants and other non-grant funded projects. Columbia received $5 thousand in FY 2024 related to a federal award for Advanced Remote Monitoring. Business Development received multiple grants and other non-grant funds attributable to various activities in fiscal year 2024. These included $403 thousand related to three separate vehicle electrification grants through Washington State Department of Commerce; $228 thousand related to vehicle electrification through a Washington State Department of Transportation grant; $116 thousand related to the Alternative Fuel Vehicle Refueling Property Credit under the Inflation Reduction Act; and $5.49 million in contributions from third party entities towards a feasibility study for an advanced nuclear reactor.

D) Nuclear Fuel: Energy Northwest has various agreements for uranium concentrates, conversion, and enrichment to provide for short-term enriched uranium product and long-term enrichment services. All expenditures related to the initial purchase of nuclear fuel for Columbia are carried at cost.

E) Decommissioning Liability: Energy Northwest has adopted GASB Statement No. 83 "Certain Asset Retirement Obligations". GASB No. 83 addresses accounting and financial reporting for certain asset retirement obligations (AROs). An ARO is a legally enforceable liability associated with the retirement of a tangible capital asset. Legal obligations exist for Energy Northwest to perform future asset retirement activities related to certain tangible assets. Accordingly, GASB No. 83 requires recognizing a liability for this obligation. (See Note 9)

F) Decommissioning and Site Restoration: Energy Northwest established decommissioning and site restoration funds for Columbia and monies are being deposited each year in accordance with an established funding plan (See Note 9).

G) Restricted Assets: In accordance with bond resolutions, related agreements and laws, separate restricted accounts have been established. These assets are restricted for specific uses including debt service, construction, capital additions, fuel purchases and workers' compensation. Short term restricted assets are included in current assets and longer-term restricted assets are shown as non-current assets. When both restricted and unrestricted resources are available for use, it is Energy Northwest's policy to use restricted resources first, then unrestricted resources as they are needed.

H) Cash and Investments: For purposes of the Statement of Cash Flows, cash includes unrestricted and restricted cash balances, and each business unit maintains its cash and investments. Short-term highly liquid investments, which mature in a year or less, are not considered to be cash equivalents; and are stated at fair value with unrealized gains and losses reported in investment income (See Note 3). Energy Northwest resolutions and investment policies limit investment authority to obligations of the United States Treasury, Federal National Mortgage Association and Federal Home Loan Banks. Safe keeping agents, custodians, or trustees hold all investments for the benefit of the individual Energy Northwest business units.

I) Accounts Receivable: The percentage of sales method is used to estimate uncollectible accounts. The reserve is then reviewed for adequacy against an aging schedule of accounts receivable. Accounts deemed uncollectible are transferred to the provision for uncollectible accounts on a yearly basis. Accounts receivable specific to each business unit are recorded in the residing business unit. In FY 2024 the evaluation of current accounts receivable resulted in no allowance for uncollectible accounts being recorded. The total balance for uncollectible receivables is zero.

J) Other Receivables: Other receivables include amounts related to the Internal Service Fund from miscellaneous outstanding receivables from other business units which have not yet been collected. The amounts due to each business unit are reflected in Due To/From other business units. Other receivables specific to each business unit are recorded in the residing business unit. No allowances were deemed necessary at the end of the fiscal year. Payments made by members in advance of expenses incurred are included as advances from members in the Statement of Net Position.

K) Materials and Supplies: Materials and supplies are valued at cost using the weighted average cost method.

L) Prepayments: Prepayments include amounts that have been paid for in advance of services being provided and are expensed over the period of service, which can be for more than one year. Prepayments include software maintenance fees and insurance premiums.

M) Leases: For long-term leases that have a present value of future payments over a certain dollar value for each business unit, which do not transfer ownership of the underlying asset, and EN is the lessee, a lease liability, and a lease asset have been established in accordance with GASB Statement No. 87 (See Note 13). The lease liability was established at the present value of payments expected to be made during the lease term (less any lease incentives). The lease asset was established at the amount of the initial measurement of the lease liability, plus any payments made to the lessor at or before the commencement of the lease term and certain direct costs.

For long term leases that have a present value of future receipts over a certain dollar value for each business unit, which EN Is the lessor, a lease receivable and a deferred inflow of resources have been established in accordance with GASB Statement No. 87 (See Note 13). The lease receivable was established at the present value of lease payments expected to be received during the lease term. The deferred inflow of resources was established at the value of the lease receivable plus any payments received at or before the commencement of the lease term that relate to future periods.

Energy Northwest has adopted a policy to recognize leases of which the present value of future payments exceeds $100 thousand for Columbia, $5 thousand for Business Development Fund, $25 thousand for Internal Service Fund, $50 thousand for Unit 1, $5 thousand for Nine Canyon, and $5 thousand for Packwood.

N) Long-Term Liabilities: Consist of obligations related to bonds payable and the associated premiums/discounts and gains/losses. Other noncurrent liabilities are pension liabilities recognized according to GASB Statement No. 68 (See Note 6), asset retirement obligations (ARO) (See Note 9), other postemployment benefits (OPEB) liabilities (See Note 12), lease liability (See Note 13), and other immaterial liabilities. The following table summarizes activities for all long-term liabilities excluding pension, OPEB, leases, and decommissioning liabilities.

Long-Term Liabilities (Dollars in thousands)

		Balance 6/30/2023		Increase		Decrease		Balance 6/30/2024
Columbia Generating Station								
Revenue bonds payable	$	3,137,845	$	527,885	$	522,730	$	3,143,000
Unamortized (discount)/premium on bonds - net		432,541		71,478		61,288		442,731
Current maturities of long-term debt		45,220		150,645		45,220		150,645
Other noncurrent liabilities		100		5		-		105
	$	3,615,706	$	750,013	$	629,238	$	3,736,481
Nuclear Project No.1								
Revenue bonds payable	$	809,145	$	189,770	$	197,110	$	801,805
Unamortized (discount)/premium on bonds - net		63,126		7,336		20,613		49,849
	$	872,271	$	197,106	$	217,723	$	851,654
Nuclear Project No.3								
Revenue bonds payable	$	950,745	$	122,550	$	135,595	$	937,700
Unamortized (discount)/premium on bonds - net		84,967		12,987		23,106		74,848
	$	1,035,712	$	135,537	$	158,701	$	1,012,548
Nine Canyon Wind Project								
Revenue bonds payable	$	31,965	$	-	$	3,960	$	28,005
Unamortized (discount)/premium on bonds - net		1,927		-		461		1,466
Current maturities of long-term debt		10,255		3,960		10,255		3,960
	$	44,147	$	3,960	$	14,676	$	33,431
Internal Service Fund								
Other noncurrent liabilities	$	2		-	$	2	$	-
	$	2		-	$	2	$	-

O) Debt Premium, Discount and Expense: Original issue and reacquired bond premiums, discounts relating to the bonds are amortized over the terms of the respective bond issues using the bonds outstanding method which approximates the effective interest method. Gains and losses on debt refundings have been deferred and amortized as a component of interest expense over the shorter of the remaining life of the old or new debt. Expenses related to debt issuance are expensed as incurred.

Senior Lien Bonds (Bearer Bonds) were issued for Project 1, Columbia, Project 3, and Packwood. At the time of issuance there were no registration requirements on the bonds. While the amount of the bearer bonds outstanding is unknown, Energy Northwest recognizes there is a contingency related to this debt that may be redeemed in the future. An estimated amount of cash required for the unpresented bonds was calculated and the Energy Northwest Custodial Account Tracking is done by US Bank. The bank holds an estimate of cash required to pay claims on these bonds. Once the bond has matured the cash is released to Energy Northwest. Once identified by the bank the designated maturity requirements have been met, the cash is provided to Energy Northwest. These escheated funds are then returned to Bonneville Power Administration. Energy Northwest maintains a $500 thousand liability on the balance sheet for the unclaimed bearer bonds and related cash to pay for claims as necessary and annually replenishes the funds through a contract with Bonneville Power Administration.

P) Revenue and Expenses: Energy Northwest accounts for expenses and revenues on an accrual basis, and recovers, through various agreements, actual cash requirements for operations and debt service for Columbia, Packwood, Nuclear Project No. 1 and Nuclear Project No. 3. For these business units, Energy Northwest recognizes revenues equal to expenses for each period. Revenues of Nuclear Project No.1 and Nuclear Project No.3 are recorded under other income and expense, as these two business units are terminated nuclear projects. No net revenue or loss is recognized, and no net position is accumulated. The difference between cumulative billings received and cumulative expenses is recorded as either billings advances from members and others (other credits) or as costs in excess of billings (other charges), as appropriate. Such amounts will be settled during future operating periods (See Note 5).

The difference between cumulative revenues and cumulative expenses for Packwood Hydroelectric, Nine Canyon and Business Development is recognized as net income or loss and included in Net Position for each period.

Energy Northwest distinguishes operating revenues and expenses from other income and expense items. Operating revenues and expenses generally result from the Net Billing agreements stated above or from services provided by EN's principal operations. Operating expenses for Energy Northwest include the costs of operating the generation producing facility, related administrative fees, and depreciation on utility plant. All revenues and expenses not meeting this definition are reported as other income or expense.

Q) Compensated Absences: Employees earn leave in accordance with length of service. Energy Northwest accrues the cost of personal leave in the year when earned. The liability for unpaid leave benefits and related payroll taxes was $27.1 million at the end of this fiscal year and is recorded as a current liability under accounts payable and accrued expenses.

R) Use of Estimates: The preparation of Energy Northwest financial statements in conformity with GAAP requires management to make estimates and assumptions that directly affect the reported amounts of assets and liabilities, disclosures of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenue and expenses during the reporting period. Actual results could differ from these estimates. Certain incurred expenses and revenues are allocated to the business units based on specific allocation methods that management considers to be reasonable.

S) Deferred Inflows and Outflows: Deferred outflows of resources are defined as the consumption of net assets by Energy Northwest that are applicable to a future reporting period and are reported in the statement of financial position in a separate section following assets. Deferred inflows of resources are defined as acquisitions of net assets by Energy Northwest that is applicable to a future reporting period and are reported in the statement of financial position in a separate section following liabilities.

These amounts consist of losses and gains on bond refundings, subsequent contributions, difference between projected and actual investment income, decommissioning costs (See Note 9), OPEB cost (See Note 12), lease cost (See note 13) and other pension related costs (See Note 6) as labeled on the Statement of Net Position.

T) Short-Term Debt: A revolving loan agreement, Electric Revenue Bond Anticipation Note 2020A/B, was amended on April 30, 2021, to fund operations and maintenance expense and debt service for Columbia as well as a portion of debt service for Project 1 and Project 3. The 2020A/B Note agreement is not to exceed $110 million with a final maturity of April 30, 2024. As of April 30, 2024, the revolving loan agreement has been terminated.

No assets were directly pledged as collateral for the above-mentioned loan agreement. The loan agreement was supported by the Net Billing Agreements with the Bonneville Power Administration and the Project Participants. The 2020A/B Note was secured by revenues of the Columbia Generating Station; no assets secure the Notes. A portion of the Electric Revenue Bond Anticipation Note, 2020A/B was secured by revenues of Project 1 and Project 3. The covenants include covenants to (1) comply with laws and relevant resolutions, (2) maintain the facilities comprising and obtain insurance on Columbia, (3) collect sufficient rates and charges to repay the Notes and all other obligations of Columbia, and (4) not to rescind or amend the project related documents or authorizing documents in any material way. Events of default include failure to repay the Notes or any Columbia, Project 1, or Project 3 bonds when due, any representation is materially incorrect, covenant defaults, invalidity, insolvency, and a judgment in excess of $15 million that is not satisfied or appealed. Remedies upon an event of default include (1) the Notes will bear interest at a default rate, (2) acceleration, but only if the Parity Bonds have been accelerated and such acceleration does not violate state law or the Columbia, Project 1, or Project 3 bond resolutions, and revenues will be turned over to the trustee for the Columbia, Project 1, or Project 3 bonds.

Short-term Liabilities (Dollars in thousands)

	Balance Outstanding 6/30/2023	Increases	Decreases	Balance Outstanding 6/30/2024
Columbia Generating Station				
Non-Revolving Loan	$ 26,850	$ -	$ 26,850	$ -

U) Pensions: For purposes of measuring the net pension liability (asset), deferred outflows of resources and deferred inflows of resources related to pensions, and pension expense, information about the fiduciary net position of the Washington State Public Employees Retirement System (PERS) and additions to/deductions from PERS' fiduciary net position have been determined on the same basis as they are reported by PERS. For this purpose, benefit payments (including refunds of employee contributions) are recognized when due and payable in accordance with the benefit terms, investments are reported at fair value.

V) OPEB: For purposes of measuring the net OPEB liability, deferred outflows of resources and deferred inflows of resources related to OPEB related to the implicit benefit of receiving medical through PERS have been recorded. Energy Northwest does not directly contribute to any post-employment benefit related to medical insurance.

W) Subscription-Based Information Technology Arrangements (SBITA): For long-term SBITAs that have a present value of future payments over a certain dollar value for each business unit, a SBTA liability, and a SBITA asset have been established in accordance with GASB Statement No. 96 (See Note 14). To be included the present value of future payments need to be for Columbia SBITAs of $100 thousand or greater, for Business Development Fund SBITAs of $5 thousand or greater, for Internal Service Fund SBITAs of $25 thousand or greater, for Unit 1 SBITAs of $50 thousand or greater, for Nine Canyon SBITAs of $5 thousand or greater, and for Packwood SBITAs of $5 thousand or greater. The SBITA liability was established at the present value of payments expected to be made during the SBITA term. The SBITA asset was established at the amount of the initial measurement of the SBITA liability.

X) Preliminary Survey and Investigation: The balance represents initial project engineering and feasibility study costs related to the construction of an advanced nuclear reactor. The balance will be capitalized upon commencement of the project. During FY 2024, Energy Northwest entered into a joint development agreement with X-energy establishing the schedule, framework and responsibilities necessary for development of an Xe-100 project on the location of Unit 1. The agreement details a project consisting of up to a dozen 80 megawatt Xe-100 modules, with a potential total output of 960 MW, with commercial operation for the first module by December 31, 2030. However, this agreement does not bind Energy Northwest to any future financial or contractual obligations, but provides Energy Northwest with the exclusive option to develop the second Xe-100 plant. Also, during FY 2024, Energy Northwest BDF signed an agreement with Puget Sound Energy, to provide up to $10 million toward Energy Northwest's feasibility study for the Xe-100 project. This agreement does not commit Puget Sound Energy to any future financial commitment nor signify an ownership interest in a developed project. In addition, in March 2024, Washington state legislators included a $25 million provision in the states 2023-2025 supplemental capital budget to support the feasibility study. The Act was signed by the Governor of Washington in March. However, the funding comes from an account created by the Climate Commitment Act (Act), which is subject to a November 2024 ballot initiative to repeal the Act. If the Act is repealed, the budget proviso would have to be reintroduced in the legislature with an alternative funding source.

NOTE 2 - Utility Plant

Utility plant activity for the year ended June 30, 2024 was as follows (Dollars in thousands):

	Balance 6/30/2023	Capital Acquisitions	Sale or Other Dispositions	Balance 6/30/2024
Columbia Generating Station				
Generation	$ 4,926,535	$ 24,909	$ (40)	$ 4,951,404
Intangible Right-To-Use Lease Asset	6,067	-	-	6,067
Intangible Right-To-Use Subscription Asset	531	214	(118)	627
Intangible Plant	47,718	721	-	48,439
Construction Work in Progress	87,271	104,707	(25,630)	166,348
Accumulated Depreciation	(3,374,003)	(99,215)	40	(3,473,178)
Accumulated Depreciation Capital Leases	(1,578)	(799)	-	(2,377)
Accumulated Depreciation Subscription Leases	(207)	(169)	118	(258)
Utility Plant net*	$ 1,692,334	$ 30,368	$ (25,630)	$ 1,697,072
Packwood Lake Hydroelectric Project				
Generation	$ 19,070	$ 876	$ (35)	$ 19,911
Intangible Right-To-Use Lease Asset	28	75	(28)	75
Intangible Plant	3,737	-	-	3,737
Accumulated Depreciation	(14,467)	(315)	35	(14,747)
Accumulated Depreciation Capital Leases	(22)	(12)	28	(6)
Utility Plant net	$ 8,346	$ 624	$ -	$ 8,970
Business Development				
Generation	$ 16,685	$ 1,497	$ (125)	$ 18,057
Intangible Right-To-Use Lease Asset	135	-	-	135
Accumulated Depreciation	(5,367)	(950)	125	(6,192)
Accumulated Depreciation Capital Leases	(11)	(6)	-	(17)
Utility Plant net	$ 11,442	$ 541	$ -	$ 11,983
Nine Canyon Wind Project				
Generation	$ 133,846	$ 28	$ (38)	$ 133,836
Intangible Right-To-Use Lease Asset	836	-	-	836
Accumulated Depreciation	(121,561)	(3,197)	38	(124,720)
Accumulated Depreciation Capital Leases	(63)	(32)	-	(95)
Utility Plant net*	$ 13,058	$ (3,201)	$ -	$ 9,857
Internal Service Fund				
Generation	$ 53,753	$ 5,643	$ (448)	$ 58,948
Intangible Right-To-Use Lease Asset	-	126	-	126
Intangible Right-To-Use Subscription Asset	3,871	3,660	(41)	7,490
Accumulated Depreciation	(41,568)	(3,988)	448	(45,108)
Accumulated Depreciation Capital Leases	-	(39)	-	(39)
Accumulated Depreciation Subscription Leases	(1,604)	(2,080)	41	(3,643)
Utility Plant net	$ 14,452	$ 3,322	$ -	$ 17,774
Nuclear Project No.1				
Intangible Right-To-Use Lease Asset	$ 1,532	$ -	$ (74)	$ 1,458
Accumulated Depreciation Capital Leases	(163)	(47)	74	(136)
Lease Plant net	$ 1,369	$ (47)	$ -	$ 1,322

* Does not include nuclear fuel, net of amortization

NOTE 3 - Investments

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

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

Concentration of credit risk: Energy Northwest's investment policy has restrictions on concentration of credit risk. No limits of concentration are set on U.S. Treasury related to securities or cash holdings. Excluding the exceptions noted, no more than 50% of the entity's total Investment portfolio will be invested in a single security type or with a single financial Institution.

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

Custodial credit risk, investments: For an investment, custodial credit risk is the risk that, in the event of failure of the counterparty, Energy Northwest will not be able to recover the value of its investments or collateral securities in possession of an outside party. Energy Northwest's investment policy addresses this risk. All securities owned by Energy Northwest are held by a third-party custodian, acting as an agent for Energy Northwest under the terms of a custody agreement.

Fair Value: Energy Northwest investments have been adjusted to reflect available fair value as of June 30, 2024, obtained from available financial industry valuation sources. Investments are valued using Bloomberg Investor Service by taking the information available on the last business day of each month. Energy Northwest categorizes its fair value measurements within the fair value hierarchy established by GAAP. The hierarchy is based on the valuation inputs used to measure the fair value of the asset. Level 1 inputs are quoted prices in active markets for identical assets; Level 2 inputs are significant other observable inputs; Level 3 inputs are significant unobservable inputs. All Energy Northwest fair market measurements are quoted at Level 2.

Investments (Dollars in thousands)

	Amortized Cost	Unrealized Gains	Unrealized Losses	Fair Value (1) (2)
Columbia	$ 252,731	$ -	$ (132)	$ 252,599
Packwood	809	-	(1)	808
Nuclear Project No. 1	-	-	-	-
Nuclear Project No. 3	-	-	-	-
Business Development Fund	6,361	-	(93)	6,268
Internal Service Fund	11,942	-	(570)	11,372
Nine Canyon Wind	13,000	-	(203)	12,797

(1) All investments are in U.S. Government backed securities including U.S. Government Agencies and Treasury Bills.

(2) The majority of investments have maturities of less than 1 year. Approximately $20.05 million have a maturity beyond 1 year with the longest maturity being March 31, 2026.

Investment Concentration FY 2024

Investment Type	Rating	June 30, 2024
Federal Home Loan Bank	AA+	37%
Federal National Mortgage Assn.	AA+	3%
U.S. Treasury	AA+	60%
		100%

NOTE 4 - Long-Term Debt

Each Energy Northwest business unit is financed separately. The resolutions of Energy Northwest authorizing issuance of revenue bonds for each business unit provide that such bonds are payable from the revenues of that business unit. All bonds issued under resolutions Nos. 769, 775 and 640 for Nuclear Projects Nos. 1, 3 and Columbia, respectively, have the same priority of payment within the business unit (the "prior lien bonds"). No prior lien bonds remain outstanding related to Columbia authorized under resolution No. 640. No prior lien bonds remain outstanding related to Project 1 authorized under resolution No. 769. No prior lien bonds remain outstanding related to Project 3 authorized under resolution No. 775. All bonds issued under resolutions Nos. 835, 838 and 1042 (the "electric revenue bonds") for Nuclear Projects Nos. 1, 3 and Columbia, respectively, are subordinate to the prior lien bonds and have the same subordinated priority of payment within the business unit. Nine Canyon's bonds were authorized by the following resolutions: Resolution

No. 1214 (2001 Bonds), Resolution No. 1299 (2003 Bonds), Resolution No. 1376 (2005 Bonds), Resolution No.1482 (2006 Bonds), Resolution No. 1722 (2012 Bonds), Resolution No. 1789 (2014 Bonds), and Resolution No. 1824 (2015 Bonds). No 2001, 2003, 2005, 2006, 2012, or 2014 Nine Canyon bonds remained outstanding as of June 30, 2024 under Resolution Nos. 1214, 1299, 1376, 1482, 1722, and 1789 respectively.

During the year ended June 30, 2024, Energy Northwest issued, for Project 1, Columbia, and Project 3 2024-A and 2024-B fixed-rate bonds. The Project 1 bonds were issued with a coupon interest rate of 5.00 percent. Columbia bonds were issued with a coupon interest rate of 5.00 percent. Project 3 bonds were issued with a coupon Interest rate of 5.00 percent.

The Series 2024-A and 2024-B bonds issued for Project 1, Columbia, and Project 3 are tax-exempt fixed-rate bonds. The 2024-A and 2024-B bonds were issued in majority to refund prior Project 1, Columbia, and Project 3 bonds and associated unamortized premium (represented as a portion of interest expense) along with the issuance of $227.447 million to fund fiscal year 2025 capital related expenses. The 2024-A refunding bonds resulted in an economic gain of $23.175 million for Columbia and $0.138 million for Project 3. The 2024-B refunding bonds resulted in an economic gain of $6.893 million for Project 1 and $5.563 million for Project 3.

Energy Northwest also defeased certain revenue bonds by placing the net proceeds from the refunding bonds in irrevocable trusts to provide for all required future debt service payments on the refunded bonds until the dates of redemption. Accordingly, the trust account assets and liabilities for the defeased bonds are not included in the financial statement. In FY 2024 total defeasements included $197.11 million for project 1, $372.085 million for Columbia, and $135.595 million for Project 3.

The Weighted Average Coupon Interest Rates and Total Defeased Bonds for 2024-A and 2024-B are presented in the following tables:

Weighted Average Coupon Interest Rate for Refunded Bonds

	2024A	2024B
Project 1	N/A	5.00%
Columbia	4.96%	N/A
Project 3	4.95%	5.00%
Total	4.95%	5.00%

Weighted Average Coupon Interest Rate for New Bonds

	2024A	2024B
Project 1	N/A	5.00%
Columbia	5.00%	5.00%
Project 3	5.00%	5.00%
Total	5.00%	5.00%

Total Defeased (Dollars in thousands)

	2024A	2024B	Total
Project 1	$ -	$ 197,110	$ 197,110
Columbia	$ 372,085	$ -	$ 372,085
Project 3	$ 63,290	$ 72,305	$ 135,595
Total	$ 435,375	$ 269,415	$ 704,790

2024 Refunding results

Outstanding principal on revenue and refunding bonds as of June 30, 2024, and future debt service requirements for these bonds are presented in the following tables:

2024-A (Tax-Exempt) Transaction	Columbia	Project 3
Cash flow difference		
Old debt service cash flows	$ 466,038	$ 63,290
New debt service cash flows	501,849	84,624
Net cash flow savings (dissavings)	$ (35,810)	$ (21,334)
Economic gain / loss		
Present value of old debt service cash flows	$ 398,049	$ 63,054
Present value of new debt service cash flows	374,874	62,916
Economic gain (loss)	$ 23,175	$ 138

Source: Provided by JP Morgan (lead underwriting bank)

2024-B (Tax-Exempt) Transaction	Project 1	Project 3
Cash flow difference		
Old debt service cash flows	$ 222,069	$ 88,574
New debt service cash flows	214,677	82,310
Net cash flow savings (dissavings)	$ 7,393	$ 6,264
Economic gain / loss		
Present value of old debt service cash flows	$ 207,610	$ 79,192
Present value of new debt service cash flows	200,718	73,628
Economic gain (loss)	$ 6,893	$ 5,563

Source: Provided by Wells Fargo (led the 2024B transaction)

Columbia Generating Revenue and Refunding Bonds

(Dollars in thousands)

Series	Coupon Rate (%)	Serial or Term Maturities	Original Issue Amount	Amount Outstanding
2010D	5.71	7/1/2024	155,805	132,380
2012E	3.25-3.60	7/1/2024-7/1/2027	748,515	63,810
2014B	4.05	7/1/2030	90,520	1,090
2015A	4.00-5.00	7/1/2029-7/1/2038	330,460	265,725
2015B	2.81	7/1/2024	329,175	3,505
2015C	5.00	7/1/2030-7/1/2031	38,525	38,525
2016A	5.00	7/1/2028-7/1/2032	89,055	59,545
2016B	3.20	7/1/2028	4,085	1,985
2017A	5.00	7/1/2029-7/1/2035	188,130	159,415
2017B	3.39	7/1/2029	3,795	3,285
2018A	4.00-5.00	7/1/2028-7/1/2034	320,510	87,745
2018C	5.00	7/1/2030-7/1/2034	229,025	203,975
2019A	5.00	7/1/35-7/1/2038	251,575	214,415
2019B	2.60-3.46	7/1/2024-7/1/2035	18,330	15,625
2020A	4.00-5.00	7/1/2030-7/1/2039	288,560	282,035
2020B	2.45	7/1/2032	14,830	13,220
2021A	4.00-5.00	7/1/2040-7/1/2042	524,090	304,715
2021B	0.90-2.35	7/1/2025-7/1/2034	100,750	100,750
2022A	5.00	7/1/2032-7/1/2037	396,180	396,180
2022B	3.32	7/1/2025	1,655	1,655
2023A	4.00-5.00	7/1/2029-7/1/2039	416,180	416,180
2024A	5.00	7/1/2030-7/1/2040	517,755	517,755
2024B	5.00	7/1/2032	10,130	10,130
Revenue bonds payable				$ 3,293,645

Nuclear Project No. 3 Refunding Revenue Bonds

(Dollars in thousands)

Series	Coupon Rate (%)	Serial or Term Maturities	Original Issue Amount	Amount Outstanding
2015A	5.00	7/1/2025-7/1/2026	79,040	74,585
2015C	5.00	7/1/2026	26,675	26,675
2016A	5.00	7/1/2026-7/1/2027	198,535	190,110
2016B	3.05	7/1/2027	5,420	4,070
2017A	5.00	7/1/2025-7/1/2028	154,435	141,780
2017B	2.94	7/1/2025	1,645	905
2018C	4.00-5.00	7/1/2025-7/1/2028	399,155	267,590
2021A	4.00	7/1/2042	16,675	16,675
2022A	5.00	7/1/2035	18,560	18,560
2023A	5.00	7/1/2033	74,200	74,200
2024A	5.00	7/12031-7/1/2037	55,650	55,650
2024B	5.00	7/1/2028	66,900	66,900
Revenue bonds payable				$ 937,700

Nuclear Project No. 1 Refunding Revenue Bonds

(Dollars in thousands)

Series	Coupon Rate (%)	Serial or Term Maturities	Amount	Outstanding
2015A	5.00	7/1/2027-7/1/2028	117,815	50,345
2015C	3.00-5.00	7/1/2025	44,005	44,005
2016A	5.00	7/1/2025	195,525	129,910
2017A	5.00	7/1/2026-7/1/2028	237,685	148,070
2017B	2.94	7/1/2025	2,160	525
2020A	5.00	7/1/2027-7/1/2028	52,760	52,760
2021A	4.00-5.00	7/1/2026-7/1/2042	69,835	69,835
2021B	0.90	7/1/2025	375	375
2022A	5.00	7/1/2026-7/1/2035	99,215	99,215
2022B	3.32	7/1/2025	560	560
2023A	5.00	7/1/2034	16,435	16,435
2024B	5.00	7/1/2025-7/1/2027	189,770	189,770
Revenue bonds payable				$ 801,805

Nine Canyon Wind Project Revenue and Refunding Bonds

(Dollars in thousands)

Series	Coupon Rate (%)	Serial or Term Maturities	Original Issue Amount	Amount Outstanding
2015	4.00-5.00	7/1/2024-7/1/2030	54,895	31,965
Revenue bonds payable				$ 31,965

Debt Service Requirements As of June 30, 2024
(Dollars in thousands)

Columbia Generating Station

FISCAL YEAR*	PRINCIPAL	INTEREST	TOTAL
6/30/2024 Balance:**	$ 150,645	$ 75,331	$ 225,976
2025	19,585	153,340	172,925
2026	18,650	149,874	168,524
2027	14,960	149,220	164,180
2028	58,075	148,681	206,756
2029	82,310	145,813	228,123
2030-2034	1,169,200	610,232	1,779,432
2035-2039	1,383,400	300,225	1,683,625
2040-2042	396,820	32,375	429,195
	$ 3,293,645	$ 1,765,091	$ 5,058,736

* Fiscal year for this report indicates the cash funding requirement year.
** Principal and Interest due July 1, 2024.

Nuclear Project No. 1

FISCAL YEAR*	PRINCIPAL	INTEREST	TOTAL
6/30/2024 Balance:**	$ -	$ 19,979	$ 19,979
2025	234,905	40,620	275,525
2026	193,105	28,183	221,288
2027	169,505	18,527	188,032
2028	153,410	10,052	163,462
2029	-	2,382	2,382
2030-2034	16,435	11,908	28,343
2035-2039	18,195	4,160	22,355
2040-2042	16,250	1,950	18,200
	$ 801,805	$ 137,761	$ 939,566

* Fiscal year for this report indicates the cash funding requirement year.
** Principal and Interest due July 1, 2024.

Nuclear Project No. 3

FISCAL YEAR*	PRINCIPAL	INTEREST	TOTAL
6/30/2024 Balance:**	$ -	$ 23,604	$ 23,604
2025	120,440	47,254	167,694
2026	175,390	40,587	215,977
2027	173,690	31,836	205,526
2028	303,095	23,242	326,337
2029	-	8,088	8,088
2030-2034	99,200	32,978	132,178
2035-2039	49,210	8,861	58,071
2040-2042	16,675	2,001	18,676
	$ 937,700	$ 218,451	$ 1,156,151

* Fiscal year for this report indicates the cash funding requirement year.
** Principal and Interest due July 1, 2024.

Nine Canyon Wind Project

FISCAL YEAR*	PRINCIPAL	INTEREST	TOTAL
6/30/2024 Balance:**	$ 3,960	$ 701	$ 4,661
2025	4,160	1,206	5,366
2026	4,370	998	5,368
2027	4,585	779	5,364
2028	4,770	596	5,366
2029	4,960	405	5,365
2030	5,160	206	5,366
	$ 31,965	$ 4,891	$ 36,856

* Fiscal year for this report indicates the cash funding requirement year.
** Principal and Interest due July 1, 2024.

NOTE 5 - Net Billing

Security - Nuclear Projects Nos. 1 and 3 and Columbia

The participants have purchased all the capability of Nuclear Projects Nos. 1 and 3 and Columbia. BPA has in turn acquired the entire capability from the participants under contracts referred to as net-billing agreements. Under the net-billing agreements for each of the business units, participants are obligated to pay Energy Northwest a pro-rata share of the total annual costs of the respective projects, including debt service on bonds relating to each business unit. BPA is then obligated to reduce amounts from participants under BPA power sales agreements by the same amount. The net-billing agreements provide that participants and BPA are obligated to make such payments whether or not the projects are completed, operable or operating and notwithstanding the suspension, interruption, interference, reduction or curtailment of the projects' output.

On May 13, 1994, Energy Northwest's Board of Directors adopted resolutions terminating Nuclear Projects Nos. 1 and 3. The Nuclear Projects Nos. 1 and 3 project agreements and the net-billing agreements, except for certain sections which relate only to billing processes and accrued liabilities and obligations under the net-billing agreements, ended upon termination of the projects. Energy Northwest previously entered into an agreement with BPA to provide for continuation of the present budget approval, billing, and payment processes. With respect to Nuclear Project No. 3, the ownership agreement among Energy Northwest and private companies was terminated in FY 1999 (See Note 10).

Security - Packwood Lake Hydroelectric Project

Power produced by Packwood is provided to the 12 member utilities. The member utilities pay the annual costs, including any debt service, of Packwood and are obligated to pay these annual costs whether Packwood is operational. The Packwood participants also share project revenue to the extent that the amounts exceed project costs.

NOTE 6 - Pension Plans

The following table represents the aggregate pension amounts for all plans as of and for the fiscal year ended June 30, 2024 (in thousands):

Pension Liabilities	$	19,502
Pension Assets	$	(45,190)
Deferred Outflows of Resources	$	47,122
Deferred Inflows of Resources	$	26,959
Pension Expense/(Revenue)	$	(7,228)

State Sponsored Pension Plans - Substantially all of Energy Northwest's full-time and qualifying part-time employees participate in one of the following statewide retirement systems administered by the Washington State Department of Retirement Systems, under cost-sharing, multiple-employer public employee defined benefit and defined contribution retirement plans. The state Legislature establishes, and amends, laws pertaining to the creation and administration of all public retirement systems.

The Department of Retirement Systems (DRS), a department within the primary government of the State of Washington, issues a publicly available annual comprehensive financial report (ACFR) that includes financial statements and required supplementary information for each plan. The DRS ACFR may be obtained by writing to:

Department of Retirement Systems
Communications Unit
PO Box 48380
Olympia, WA 98540-8380

Or the DRS ACFR may be downloaded from the DRS website at www.drs.wa.gov.

Public Employees Retirement System (PERS)

PERS members include elected officials; state employees; employees of local governments; and higher education employees not participating in higher education retirement programs.

PERS is composed of and reported as three separate plans for accounting purposes: Plan 1, Plan 2/3 and Plan 3. Plan 1 accounts for the defined benefits of Plan 1 members. Plan 2/3 accounts for the defined benefits of Plan 2 members and the defined benefit portion of benefits for Plan 3 members. Plan 3 accounts for the defined contribution portion of benefits for Plan 3 members. Although employees can be a member of only Plan 2 or Plan 3, the defined benefits of Plan 2 and Plan 3 are accounted for in the same pension trust fund. All assets of Plan 2/3 may legally be used to pay the defined benefits of any Plan 2 or Plan 3 members or beneficiaries.

PERS Plan 1 - provides retirement, disability, and death benefits. Retirement benefits are determined as 2% of the member's average final compensation (AFC) times the member's years of service. The AFC is the average of the member's 24 highest consecutive service months. Members are eligible for retirement from active status at any age with at least 30 years of service, at age 55 with at least 25 years of service, or at age 60 with at least 5 years of service. PERS Plan 1 retirement benefits are actuarially reduced if a survivor benefit is chosen. Members retiring from active status prior to the age of 65 may also receive actuarially reduced benefits. Other benefits include an optional cost-of-living adjustment (COLA). PERS 1 members were vested after the completion of five years of eligible service. The plan was closed to new entrants on September 30, 1977.

Contributions - The PERS Plan 1 member contribution rate is established by State statute at 6%. The employer contribution rate is developed by the Office of the State Actuary, adopted by the Pension Funding Council and is subject to change by the legislature.

The PERS Plan 1 required contribution rates (expressed as a percentage of covered payroll) were as follows for the fiscal year ended June 30, 2024:

PERS Plan 1 Actual Contribution Rates	Employer	Employee
July 2023 through August 2023		
PERS Plan 1	6.36%	6.00%
PERS Plan 1 UAAL	2.85%	-
Administrative Fee	0.18%	-
Total	9.39%	6.00%
September 2023 through June 2024		
PERS Plan 1	6.36%	6.00%
PERS Plan 1 UAAL	2.97%	-
Administrative Fee	0.20%	-
Total	9.53%	6.00%

Energy Northwest's actual contributions to the plan were $4.5 million for the fiscal year ended June 30, 2024.

PERS Plan 2/3 - provides retirement, disability and death benefits. Retirement benefits are determined as 2% of the member's AFC times the member's years of service for Plan 2 and 1% of AFC for Plan 3. The AFC is the average of the member's 60 highest-paid consecutive service months. Members are eligible for retirement with a full benefit at 65 with at least 5 years of service credit. Retirement before age 65 is considered an early retirement. PERS Plan 2/3 members who have at least 20 years of service credit and are 55 years of age or older, are eligible for early retirement with a benefit that is reduced by a factor that varies according to age for each year before age 65. PERS Plan 2/3 retirement benefits are actuarially reduced if a survivor benefit is chosen. Other PERS Plan 2/3 benefits include a COLA based on the CPI, capped at 3% annually. Annuities purchased with Plan 3 defined contributions that are invested within the Washington State Investment Board (WSIB) Total Allocation Portfolio (TAP) are considered defined benefits. Plan 3 WSIB TAP annuities are actuarially reduced if a survivor benefit is chosen and TAP annuities include a COLA of 3% annually. PERS 2 members are vested after completing 5 years of eligible service. Plan 3 members are vested in the defined benefit portion of their plan after 10 years of service; or after 5 years of service if 12 months of that service are earned after age 44.

PERS Plan 3 - defined contribution benefits are totally dependent on employee contributions and investment earnings on those contributions. Members are eligible to withdraw their defined contributions upon separation. Members have multiple withdrawal options, including purchase of an annuity. PERS Plan 3 members are immediately vested in the defined contribution portion of their plan.

Contributions - The PERS Plan 2/3 employer and employee contribution rates are developed by the Office of the State Actuary to fully fund Plan 2 and the defined benefit portion of Plan 3. The Plan 2/3 employer rates include a component to address the PERS Plan 1 unfunded actuarially accrued liability (UAAL) and an administrative expense that is currently set at 0.18%. Each biennium, the state Pension Funding Council adopts Plan 2 employer and employee contribution rates and Plan 3 contribution rates.

As established by Chapter 41.34 RCW, Plan 3 defined contribution rates are set at a minimum of 5% and a maximum of 15%. PERS Plan 3 members choose their contribution rate from six options when joining membership and can change rates only when changing employers. Employers do not contribute to the defined contribution benefits.

The PERS Plan 2/3 required contribution rates (expressed as a percentage of covered payroll) were as follows fiscal year ended June 30, 2024:

PERS Plan 2/3 Actual Contribution Rates	Employer 2/3	Employee 2	Employee 3
July 2023 through August 2023			
PERS Plan 2/3	6.36%	6.36%	Varies
PERS Plan 1 UAAL	2.85%	-	-
Administrative Fee	0.18%	-	-
Total	9.39%	6.36%	Varies
September 2023 through June 2024			
PERS Plan 2/3	6.36%	6.36%	Varies
PERS Plan 1 UAAL	2.97%	-	-
Administrative Fee	0.20%	-	-
Total	9.53%	6.36%	Varies

Energy Northwest's actual contributions to the plan were $9.6 million for the fiscal year ended June 30, 2024.

Actuarial Assumptions

The total pension liability/(asset) (TPL/A) for each of the DRS plans was determined using the most recent actuarial valuation completed in 2023 with a valuation date of June 30, 2022. The actuarial assumptions used in the valuation were based on the results of the Office of the State Actuary's (OSA) 2013-2018 Demographic Experience Study and the 2021 Economic Experience Study.

Additional assumptions for subsequent events and law changes are current as of the 2022 actuarial valuation reports. The TPL/A was calculated as of the valuation date and rolled forward to the measurement date of June 30, 2023. Plan liabilities/(assets) were rolled forward from June 30, 2022, to June 30, 2023, reflecting each plan's normal cost (using the entry-age cost method), assumed interest and actual benefit payments.

- **Inflation:** 2.75% total economic inflation; 3.25% salary inflation
- **Salary increases:** In addition to the base salary inflation assumption, salaries are also expected to grow by promotions and longevity.
- **Investment rate of return:** 7%

Mortality rates were developed using the Society of Actuaries' Pub. H-2010 mortality rates, which vary by member status (e.g. active, retiree, or survivor), as the base table. OSA applied age offsets for each system, as appropriate, to better tailor the mortality rates to the demographics of each plan. OSA applied the long-term MP-2017 generational improvement scale, also developed by the Society Actuaries, to project mortality rates for every year after the 2010 base table. Mortality rates are applied on a generational basis; meaning, each member is assumed to receive additional mortality improvements in each future year throughout his or her lifetime.

There were no changes in the assumptions in the June 30, 2022 valuation, which was used for the June 30, 2023 measurement.

Discount Rate

The discount rate used to measure the total pension liability/(asset) for all DRS plans was 7.0%.

To determine that rate, an asset sufficiency test was completed to test whether each pension plan's fiduciary net position was sufficient to make all projected future benefit payments for current plan members. Based on OSA's assumptions, the pension plans' fiduciary net position was projected to be available to make all projected future benefit payments of current plan members. Therefore, the long-term expected rate of return of 7.0% was used to determine the total liability/(asset).

Long-Term Expected Rate of Return

The long-term expected rate of return on the DRS pension plan investments of 7.0% was determined using a building-block-method. In selecting this assumption, OSA reviewed the historical experience data, considered the historical conditions that produced past annual investment returns, and considered Capital Market Assumptions (CMAs) and simulated expected investment returns provided by the Washington State Investment Board (WSIB). The WSIB uses the CMA's and their target asset allocation to simulate future investment returns at various future times.

Estimated Rates of Return by Asset Class

The table below summarizes the best estimates of arithmetic real rates of return for each major asset class included in the pension plan's target asset allocation as of June 30, 2021. The inflation component used to create the table is 2.2% and represents the WSIB's most recent long-term estimate of broad economic inflation:

Asset Class	Target Allocation	Percent Long-Term Expected Real Rate of Return Arithmetic
Fixed Income	20%	1.50%
Tangible Assets	7%	4.70%
Real Estate	18%	5.40%
Global Equity	32%	5.90%
Private Equity	23%	8.90%
Total	100%	

Sensitivity of Net Pension Liability/(Asset)

The table below presents Energy Northwest's proportionate share of the net pension liability/(asset) calculated using the discount rate of 7%, as well as what Energy Northwest's proportionate share of the net pension liability/(asset) would be if it were calculated using a discount rate that is 1 percentage point lower (6%) or 1-percentage point higher (8%) than the current rate (in thousands).

	1% Decrease (6.0%)	Current Discount Rate (7.0%)	1% Increase (8.0%)
PERS 1	$ 27,246	$ 19,502	$ 12,744
PERS 2/3	$ 49,149	$ (45,190)	$ (122,695)

The pension liability/(asset) has been allocated to the business units based on the percentages listed in Note 1. The total pension liability/(asset) for each unit as of June 30, 2024, is as follow (in thousands):

	Energy Northwest's proportionate share of the PERS Plan 1 net pension liability/(asset):	Energy Northwest's proportionate share of the PERS Plan 2/3 net pension liability/(asset):	Total
Columbia	$ 18,081	$ (42,709)	$ (24,628)
Packwood	81	(224)	(143)
Business Development	1,082	(1,666)	(584)
Nine Canyon	172	(457)	(285)
Nuclear Project No. 1	86	(134)	(48)
Total	$ 19,502	$ (45,190)	$ (25,688)

Pension Plan Fiduciary Net Position

Detailed information about the State's pension plans' fiduciary net position is available in the separately issued DRS financial report.

Pension Liabilities (Assets), Pension Expense, and Deferred Outflows of Resources and Deferred Inflows of Resources Related to Pensions

At June 30, 2024 Energy Northwest reported a total pension liability (asset) for its proportionate share of the net pension liabilities as follows (measured as of June 30, 2023 in thousands):

PERS 1	$	19,502
PERS 2/3		(45,190)
Total	$	(25,688)

Energy Northwest's proportionate share of the collective net pension assets, deferred outflows, liabilities, and deferred inflows was as follows:

	Proportionate Share 6/30/22	Proportionate Share 6/30/23	Change in Proportion
PERS 1	0.92%	0.85%	-0.07%
PERS 2/3	1.20%	1.10%	-0.10%

Employer contribution transmittals received and processed by the DRS for the fiscal year ended June 30 are used as the basis for determining each employer's proportionate share of the collective pension amounts reported by the DRS in the Schedules of Employer and Nonemployer Allocations.

Pension Expense

For the fiscal year ended June 30, 2024, Energy Northwest's recognized pension expense/(revenue) as follows (in thousands):

PERS 1	$	(2,237)
PERS 2/3		(5,288)
Expenses		297
Total	$	(7,228)

Deferred Outflows of Resources and Deferred Inflows of Resources

At June 30, 2024, Energy Northwest reported deferred outflows of resources and deferred inflows of resources related to pensions from the following sources (in thousands):

	Deferred Outflows of Resources	Deferred Inflows of Resources
PERS 1:		
Differences between expected and actual economic experience	$ -	$ -
Changes in actuarial assumptions	-	-
Net difference between projected and actual investment earnings on pension plan investments	-	2,200
Changes in proportion and differences between contributions and proportionate share of contributions	-	-
Contributions paid to PERS subsequent to the measurement date	4,494	-
Total PERS 1	$ 4,494	$ 2,200
PERS 2/3:		
Differences between expected and actual economic experience	$ 9,205	$ 505
Changes in actuarial assumptions	18,972	4,135
Net difference between projected and actual investment earnings on pension plan investments	-	17,030
Changes in proportion and differences between contributions and proportionate share of contributions	4,808	3,089
Contributions paid to PERS subsequent to the measurement date	9,643	-
Total PERS 2/3	42,628	24,759
Total All Plans	$ 47,122	$ 26,959

Deferred outflows of resources related to pensions resulting from Energy Northwest's contributions subsequent to the measurement date will be recognized as a reduction of the net pension liability or an addition to the net pension asset in the following year. Other amounts reported as deferred outflows and deferred inflows of resources related to pensions will be recognized in pension expense as follows:

Fiscal Year Ended June 30	PERS 1	PERS 2/3
2025	(1,497)	(8,325)
2026	(1,882)	(9,891)
2027	1,161	14,372
2028	18	5,842
2029	-	5,614
Thereafter	-	614
Total	$ (2,200)	$ 8,226

NOTE 7 - Deferred Compensation Plans

Energy Northwest provides a 401(k) deferred compensation plan (401(k) plan), and a 457 deferred compensation plan. Both plans are defined contribution plans that were established to provide a means for investing savings by employees for retirement purposes. All permanent, full-time employees are eligible to enroll in the plans. Participants are immediately vested in their contributions and direct the investment of their contribution. Each participant may elect to contribute pre-tax annual compensation, subject to current Internal Revenue Service limitations.

For the 401(k) plan, Energy Northwest may elect to make an employer matching contribution for each of its employees who is a participant during the plan year. The amount of such an employer match shall be 50 percent of the maximum salary deferral percentage. During FY 2024 Energy Northwest contributed $4.1 million in employer matching funds while employees contributed $12.9 million.

NOTE 8 - Nuclear Licensing and Insurance

Nuclear Licensing

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

Nuclear Insurance

Nuclear insurance includes liability coverage, property damage, decontamination and premature decommissioning coverage and accidental outage and/or extra expense coverage. The liability coverage is governed by the Price-Anderson Act (Act), while the property damage, decontamination and premature decommissioning coverage are defined by the Code of Federal Regulations. Energy Northwest continues to maintain all regulatory required limits as defined by the NRC, Code of Federal Regulations, and the Act. The NRC requires Energy Northwest to certify nuclear insurance limits on an annual basis. Energy Northwest intends to maintain insurance against nuclear risks to the extent such insurance is available on reasonable terms and in an amount and form consistent with customary practice. Energy Northwest is self-insured to the extent that losses (i) are within the policy deductibles, (ii) are not covered per policy exclusions, terms and limitations, (iii) exceed the amount of insurance maintained, or (iv) are not covered due to lack of insurance availability. Such losses could have an effect on Energy Northwest's results of operations and cash flows. All dollar figures noted below are as of June 30, 2024.

American Nuclear Insurance (ANI) Coverage: The Act provides financial protection for the public in the event of a significant nuclear generation plant incident. The Act sets the statutory limit of public liability for a single nuclear incident at $16.3 billion. Energy Northwest addresses this requirement through a combination of private insurance and an industry-wide retrospective payment program called Secondary Financial Protection (SFP). Energy Northwest has $500 million of liability insurance as the first layer of protection. If any US nuclear generation plant has a significant event which exceeds the plant's first layer of protection, every operating licensed reactor in the US is subject to an assessment up to $158.026 million. Assessments are limited to $24.714 million per reactor, per year, per incident, excluding tax. The SFP is adjusted at least every 5 years to account for inflation and any changes in the number of operating plants. The SFP and liability coverage are not subject to any deductibles.

Nuclear Electrical Insurance Limited (NEIL) Coverage: The Code of Federal Regulations requires nuclear generation plant license-holders to maintain at least $1.06 billion nuclear decontamination and property damage insurance and requires the proceeds thereof to be used to place a plant in a safe and stable condition, to decontaminate it pursuant to a plan submitted to and approved by the NRC before the proceeds can be used for plant repair or restoration or to provide for premature decommissioning. Energy Northwest has aggregate coverage in the amount of $2.75 billion which is subject to a $5 million deductible per accident.

The Agency anticipates exposure to a variety of risks of loss as a normal part of conducting business (for example: torts; theft of, damage to, or destruction of assets; errors and omissions; workers compensation). These anticipated risks of losses are covered through a combination of self-insurance, commercial property and liability insurance, nuclear property and liability insurance, professional services liability insurance, Directors & Officers (including employment practices liability) insurance, and fiduciary insurance. Claims for loss to the Agency are infrequent and have not exceeded the liability policy limits in the past three years.

NOTE 9 - Decommissioning and Site Restoration - Asset Retirement Obligation (ARO)

Energy Northwest implemented GASB Statement No. 83 - "Certain Asset Retirement Obligations" and applied the statement in fiscal year 2019. For the purposes of this statement, an ARO is a legally enforceable liability associated with the retirement of a tangible capital asset (that is, the tangible capital asset is permanently removed from service). The retirement of a tangible capital asset encompasses its sale, abandonment, recycling, or disposal in some manner; however, it does not encompass temporary idling of a tangible capital asset.

AROs result from the normal operations of a tangible capital assets, whether acquired or constructed, and include legally enforceable liabilities with all the following activities:

- Retirement of a tangible capital asset
- Disposal of a replaced part that is a component of a tangible capital asset
- Environmental remediation associated with the retirement of a tangible capital asset that results from the normal operation of that capital asset

The measurement of Energy Northwest's AROs are based on the best estimate of the current value of outlays expected to be incurred. Current value is the amount that would be paid if all equipment, facilities, and services included in the estimate were acquired at the end of the accounting period. The current estimate is the basis for the ARO and corresponding liability. The recognition of the ARO at current value also results in a corresponding deferred outflow of resources.

Energy Northwest has identified the following AROs subject to GASB No. 83:

- Columbia Generating Station (includes related Columbia Site Restoration)
- Independent Spent Fuel Storage Installation (ISFSI)
- Nine Canyon Wind Farm
- Nuclear Project No. 1 site restoration
- Business Development Fund Horn Rapid Battery Energy Storage System (BESS)
- Excluded from GASB No. 83 reporting is the Packwood Hydroelectric Project. The timing and extent of any liabilities associated with operations is not determinable at this time. Packwood remains operable with no foreseeable change in operations; assumptions

is the current facility is not subject to the requirements of obtaining a current estimate of a liability with offset to deferred outflows. As such, Packwood's obligation has not been calculated because the time frame and extent of the obligation under this statement was considered indeterminate. As a result, no estimate of the ARO obligation was completed; an ARO will be recorded if future events warrant a change.

Decommissioning and site restoration requirements for Columbia, ISFSI are governed by the NRC regulations. Columbia, ISFSI and Nuclear Project No. 1 are also governed by site certification agreements between Energy Northwest and the state of Washington and regulations adopted by the Washington Energy Facility Site Evaluation Council (EFSEC) and a lease agreement with the Department of Energy ("DOE"). (See Notes 1 & 10). Nine Canyon decommissioning requirements are governed by participant agreements which are part of the 2nd Amended and Restated Nine Canyon Wind Project Power Agreement and associated land leases for location of the wind turbines. The BESS decommissioning requirements are governed by a participant agreement with the City of Richland.

Decomissioning activity

Columbia Generation Station (including site restoration)

Columbia is a 1,174-megawatt electric (MWe Design Electric rating, net) boiling water reactor located on the DOE Hanford Site north of Richland, Washington.

Columbia was issued a construction permit in March of 1973 and NRC licensing was completed in December of 1983. Columbia began commercial generation in December of 1984. An updated estimate for the ARO was completed in April of 2024 to account for the liability associated with the dismantling and decommissioning of the Columbia asset along with restoration of the leased DOE land. Both the asset decommissioning and site restoration are governed by agreements and regulations signed as part of construction and completion of Columbia.

The FY 2024 Columbia study was a joint effort between BPA and Energy Northwest to provide an updated estimate for future accounting and funding requirements to comply with GASB No. 83. The study was completed by the same national firm, who completed an original ARO estimate for Columbia in 2019. The national firm is involved with approximately 90% of cost studies completed in the United States nuclear industry. Updated design changes to the plan specifications and drawings were used as basis for the updated costing estimates. Current estimates for labor and materials were obtained and used as basis for coming up with the estimates of work to be performed. Phasing of the costs were scheduled and flowed according to two scenarios currently accepted by the NRC, DECON and SAFSTOR.

- DECON - method in which structures, systems, and components that contain radioactive contamination are removed from a site and safely disposed at a commercially operated low-level waste disposal facility or decontaminated to a level that permits the site to be released for unrestricted use shortly after it ceases operation.
- SAFSTOR - method in which a nuclear facility is placed and maintained in a condition that allows the facility to be safely stored and subsequently decontaminated (deferred decontamination) to levels that permit release for unrestricted use.

Both DECON and SAFSTOR are acceptable methods of accounting for decommissioning estimates with differences in method and timing of when the expenditures will occur after termination of the plant (currently planned for December 2043). A joint decision between BPA and Energy Northwest was made to adopt the DECON method for accounting purposes.

The FY 2024 Columbia study updated estimate using DECON increased the estimated liability from FY 2023 by $60.6 million and extended the scenario's estimated decommissioning activity completion date by two years to June 2099. In FY 2024, $41.3 million of amortization expense was recognized, the adjustment from the updated study of $60.6 million and the index adjustment for FY 2024 was $59.5 million resulting in the overall increase in deferred outflow of $78.8 million. The increase from the FY 2024 study and the index adjustment increased the estimated liability as of June 30, 2024, from $1.74 billion to $1.86 billion.

Each year the ARO is evaluated to determine if there are any material changes in timing or costs. If there are material changes, the estimate will be adjusted accordingly. If there are no material changes impacting the estimate, then a standard index will be used each year to determine current changes to the estimated derived from the original study. The amount for both the liability and deferred outflow will be increased or decreased accordingly and change the out year straight line amount for decommissioning. A decision was made to do an updated ARO estimate in FY 2024 based on increased labor and materials costs following the Covid-19 pandemic. Also, a decision has been made to do an updated estimate approximately every five years.

At the time of termination of Columbia and commencing of decommissioning activities, the liability will be decreased as cash expenditures occur through the estimated completion date of FY 2099. Upon settlement of the liability, there is potential for variances from the original estimates. If there are differences from the estimate and actual payment a gain or loss on the ARO will be recorded for the difference. However, regarding the net-billed projects, BPA is obligated to provide for the entire cost of decommissioning and site restoration; therefore, any gain or loss recognized upon settlement of the ARO results in an adjustment to either the billings in excess of costs (liability) or costs in excess of billings (asset), as appropriate, as no net revenue or loss is recognized, and no net position is accumulated for the net-billed projects.

Independent Spent Fuel Storage Installation

Energy Northwest's Independent Spent Fuel Storage Installation (ISFSI) at the Columbia Generating Station is a temporary dry cask storage facility intended to store spent nuclear reactor fuel in NRC-approved dry storage casks until the DOE completes its plan for a national repository. The ISFSI consists of two concrete pads storing a total of 36 casks and one additional pad with the capacity of 18 casks. The last ISFSI campaign, which began in March 2022, was completed in May 2022 for an additional nine casks. In order to accommodate spent fuel to be generated through the end of the plant's operating license period of December 20, 2043, Energy Northwest is expanding the ISFSI facility to store an additional 72 casks. The final phase of the ISFSI pad expansion project will be completed in the FY 2021-2025 time frame and commissioned in FY 2025, the four additional pads will have capacities of 18 casks each. Energy Northwest previously financed a portion of the cost for the construction of the existing ISFSI pads.

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

Energy Northwest established a decommissioning and site restoration plan for the ISFSI in 1997. Annual payments to a fund established pursuant to this plan began in 2003 and were held by Energy Northwest. These payments were currently scheduled to occur annually through 2044. Adoption of asset retirement accounting for the ISFSI project took place in FY 2005. The Columbia cost study completed in April 2024 included the ISFSI and revised both the timing and estimate. The FY 2024 ISFSI study updated estimate using DECON increased the estimated liability from FY 2023 by $15.3 million and extended the scenario's estimated decommissioning activity completion date by two years to June 2099. In FY 2024, $1.0 million of amortization expense was recognized, the adjustment from the updated study of $15.3 million and the index adjustment for FY 2024 was $0.8 million resulting in the overall increase in deferred outflow of $15.1 million. The increase from the FY 2024 study and the index adjustment increased the estimated liability as of June 30, 2024, from $9.0 million to $25.1 million.

Each year the ARO evaluation for the ISFSI is included as part of the Columbia review, as such, accounting and any eventual net-billed project impacts will follow the same process described above for the Columbia ARO and net-billed obligations.

The above estimates and timing do not consider any of the impacts of the current DOE litigation or potential changes in DOE handling of accumulated spent fuel being stored at the ISFSI. Note 10 - Commitments and Contingencies under other litigations and commitments describes the current status of the ISFSI settlement.

On March 21, 2021, Energy Northwest agreed to transfer existing ownership of the ISFSI trust fund to Bonneville, allowing Bonneville to appropriately manage the ISFSI fund, and in addition, access investment options unavailable to Energy Northwest under current law. Similar to the Columbia trust fund agreement with Bonneville, Energy Northwest retains all rights duties and obligations related to the decommissioning and remediation of the ISFSI facility.

Nine Canyon Wind Project

The Nine Canyon Wind Farm Project (Nine Canyon) is wholly owned and operated by Energy Northwest on leased ground located in the Horse Heaven Hills area southwest of Kennewick, Washington in Benton County. Electricity generated by Nine Canyon is purchased undersigned agreements with an end date of 2030. Under the current agreement, Nine Canyon has the obligation to remove the generation facilities upon expiration of the lease agreement if requested by the lessors. The Nine Canyon Wind Project recorded the related original ARO in FY 2003 for Phase I and II. Phase III began commercial operation in FY 2008 and the original ARO was adjusted to reflect the change in scenario for the retirement obligation, with current lease agreements reflecting a 2030 expiration date. Previous scenarios for the ARO have been factored into the participant agreements, drives the rate plan, and drives the cash requirements for debt repayment and cost of operations. Possible adjustments may be necessary to future rates depending on operating costs and any changes to the ARO.

A cost estimate was completed in FY 2018 for Nine Canyon and revised both the timing and estimate of decommissioning activities. The Nine Canyon decommissioning is projected to be completed following the 2030 expiration date of the power purchase and lease agreements and was estimated at $18.0 million (in 2019 dollars). In FY 2024, $1.1 million of amortization expense was recognized and the index adjustment for FY 2024 was $710 thousand resulting in the overall decrease in deferred outflow of $405 thousand. The index adjustment increased the estimated liability as of June 30, 2024, from $21.5 million to $22.2 million.

Each year the ARO will be evaluated to determine if there are any material changes in timing or costs. If there are material changes, the estimate will be adjusted accordingly. If there are no material changes impacting the estimate, then a standard index will be used each year to determine current changes to the estimated derived from the original study. The amount for both the liability and deferred outflow will be increased or decreased accordingly and change the out year straight line amount for decommissioning. There were no material changes in timing or costs for the Nine Canyon ARO.

At the time of termination of Nine Canyon and commencing of decommissioning activities, the liability will be decreased as cash expenditures occur through the estimated completion date of FY 2031. Upon settlement of the liability, there is potential for variances from the original estimates. If there are differences from the estimate and actual payment a gain or loss on the ARO will be recorded for the difference.

Nuclear Project No. 1

Project 1 is a partially completed nuclear electric generating project located on DOE's Hanford reservation, approximately one and one-half miles east of Columbia. Project 1 was terminated in May 1994. Energy Northwest has planned for the demolition and restoration of Nuclear Project No. 1 and is now maintaining the site to support re-use activities. The Nuclear Project No. 1 Post Termination agreement requires BPA to fund this site remediation plan. The current plan estimates final decommissioning (site remediation) to be complete in June 2025. The estimate from FY 2023 was updated to reflect an increase in planned expenses; the remaining estimate was $2.3 million as of June 30, 2023. The June 30, 2024, estimate was revised upward by $2.5 million; FY 2024 costs incurred of $0.9 million resulted in the remaining estimate of $3.9 million. Total site remediation activity costs to date are $20.9 million. Due to the re-valuation of the ARO estimate each year there are no prior year accounting impacts to the Nuclear Project No. 1 ARO as a result of adopting GASB No. 83. The asset retirement calculation has been adjusted yearly for actual costs incurred and yearly revised estimates. BPA has placed funds in an external interest-bearing trust account in order to have sufficient funds for ongoing remediation costs. The amount in the trust fund is approximately $17.0 million as of June 30, 2024. Any funds remaining after final remediation efforts are complete will be returned to BPA.

Horn Rapids Battery Storage System

The Horn Rapids Battery Energy Storage System (BESS) is a collaborative effort between Energy Northwest and the City of Richland and is part of an overall project effort commonly known as the Horn Rapids Solar, Storage, and Training Project (HRSST). HRSST Is a four MWdc Photovoltaic solar project (Energy Northwest does not own the solar portion) paired with a 1 MW/4 MWh basic lithium-ion battery storage system. Energy Northwest will operate and maintain the BESS portion of the project for the City of Richland. The City of Richland has signed a purchase power agreement for 100% of the power and reimbursement of construction and operating costs of the BESS. The BESS is located on leased property in Richland Washington. The BESS was essentially complete and operational June 30, 2021.

Total BESS costs totaled $6.3 million as of June 30, 2023. Energy Northwest was the recipient of a Washington State Department of Commerce (Commerce) grant in 2017. Commerce awarded up to $3.0 million under the Clean Energy Funds' Grid Modernization Grant Program to offset the construction of the BESS. Grant proceeds received as of June 30, 2023, were $3.0 million. Decommissioning costs are part of the agreement for reporting operating costs under the City of Richland participant agreement, therefore financial assurance is for total costs to be reimbursed by the City of Richland under the existing participant agreement. The decommissioning plan was finalized as part of the project deliverables prior to operation. Projected decommissioning costs are $40 thousand in 2021 dollars and expected to be incurred after 25 years of operation. In FY 2024, $1.8 thousand of amortization expense was recognized and the index adjustment for FY 2024 was $1.5 thousand resulting in an overall reduction to the deferred outflow of $0.3 thousand. The index adjustment increased the estimated liability as of June 30, 2024, from $45.1 thousand to $46.6 thousand.

ARO Financial Assurance

The NRC has issued rules to provide guidance to licensees of operating nuclear plants on providing financial assurance for decommissioning plants at the end of each plant's operating life. In September 1998, the NRC approved and published its "Final Rule on Financial Assurance Requirements for Decommissioning Power Reactors." As provided in this rule, each power reactor licensee is required to report to the NRC the status of its decommissioning funding for each reactor or share of a reactor it owns. This reporting requirement began March 31, 1999, and reports are required every two years thereafter. Energy Northwest submitted its most recent report to the NRC for Columbia decommissioning in March 2023. A separate requirement for providing financial assurance for ISFSI decommissioning states that a report must be provided at least every three years. Energy Northwest submitted its most recent report to the NRC for ISFSI decommissioning in November 2021.

Energy Northwest's assurance funding estimate (10 CFR 50.75 - Reporting and Recordkeeping for Decommissioning) of Columbia's plant decommissioning costs in FY 2022 dollars is $622.2 million and assurance funding estimate (10 CFR 72.30 - Reporting and Recordkeeping for Decommissioning) of Columbia's ISFSI decommissioning costs in FY 2021 dollars is $7.1 million. These estimates are updated biannually for the Columbia decommissioning and every three years for the ISFSI decommissioning with the last update for the Columbia occurring in fiscal year 2023 and for the ISFSI in fiscal year 2022. The estimates are based on the NRC minimum amount (NRC 2023 study for Columbia and the NRC 2021 study for ISFSI) required to demonstrate reasonable financial assurance for a boiling water reactor with the power level of Columbia.

Site restoration requirements for Columbia and Nuclear Project No. 1 are governed by the site certification agreements between Energy Northwest and the state of Washington and by regulations adopted by the EFSEC. Energy Northwest submitted a site restoration plan that was approved by the EFSEC on June 12, 1995. Energy Northwest's funding estimate of Columbia's site restoration costs in FY 2022 dollars is $177.2 million and is updated biannually along with the Columbia decommissioning estimate. Both decommissioning and site restoration estimates are used as the basis for establishing a funding plan that includes escalation and interest earnings until decommissioning activities occur. Payments to the decommissioning and site restoration funds have been made since January 1985.

The market value of cash and investment securities in the Columbia decommissioning, ISFSI decommissioning and site restoration funds as of June 30, 2024, totaled approximately $483.0 million, $3.7 million, and $72.8 million, respectively. The market value of cash and investment securities in the site restoration fund for Nuclear Project No. 1 is $17.0 million. Since September 1996, the Columbia and Nuclear Project No. 1 amounts have been held in an irrevocable trust that recognizes asset retirement obligations according to the fair value of the dismantlement and restoration costs of certain Energy Northwest assets. The ISFSI amounts were transferred from Energy Northwest to Bonneville as discussed above and are held in same manner as the trust funds mentioned for both Columbia and Nuclear Project No. 1. The trustee is a domestic U.S. bank that certifies the funds for use when needed to retire the asset. The trusts are funded by BPA ratepayers and managed by BPA in accordance with NRC requirements and site certification agreements; the balances in these external trust funds are not reflected on Energy Northwest's balance sheet.

Nine Canyon billing rates to power purchase participants are set to cover cash requirements of debt repayment and cost of operations. Any increases or decreases to rates will be based on cost of operations in the future. Starting in FY 2023 the power purchase participants approved applying a portion of the billed rates to be used to establish and fund a decommissioning trust. The market value of cash and investment securities in the Nine Canyon Decommissioning Trust as of June 30, 2024, totaled approximately $6.6 million.

Financial assurance and estimates for Nuclear Project No. 1 are discussed in the previous section - Decommissioning - Nuclear Project No. 1.

Financial assurance and estimates for the BESS are discussed in the previous section – Decommissioning – Horn Rapids Battery Storage System.

NOTE 10 - Commitments and Contingencies

Nuclear Project No. 1 Termination

Since the Nuclear Project No.1 termination, Energy Northwest has been planning for the demolition of Nuclear Project No. 1 and restoration of the site, recognizing the fact that there is no market for the sale of the project in its entirety, and no viable alternative use has been found to-date. The final level of demolition and restoration will be in accordance with agreements discussed below under "Nuclear Project No. 1 Site Restoration."

Nuclear Project No. 3 Termination

In June 1994, the Nuclear Project No. 3 Owners Committee voted unanimously to terminate the project. In 1995, a group from Grays Harbor County, Washington, formed the Satsop Redevelopment Project (SRP). The SRP introduced legislation with the state of Washington under Senate Bill No. 6427, which passed and was signed by the governor of the state of Washington on March 7, 1996. The legislation enables local governments and Energy Northwest to negotiate an arrangement allowing such local governments to assume an interest in the site on which Nuclear Project No. 3 exists for economic development by transferring ownership of all or a portion of the site to local government entities. This legislation also provides for the local government entities to assume regulatory responsibilities for site restoration requirements and control of water rights. In February 1999, Energy Northwest entered into a transfer agreement with the SRP to transfer the real and personal property at the site of Nuclear Project No. 3. The SRP also agreed to assume regulatory responsibility for site restoration. Therefore, Energy Northwest is no longer responsible to the state of Washington and EFSEC for any site restoration costs.

Nuclear Project No. 1 Site Restoration

Site restoration requirements for Nuclear Project No. 1 are governed by site certification agreements between Energy Northwest and the state of Washington and regulations adopted by EFSEC, and a lease agreement with DOE. Energy Northwest submitted a site restoration plan for Nuclear Project No. 1 to EFSEC on March 8, 1995, which complied with EFSEC requirements to remove the assets and restore the sites by demolition, burial, entombment, or other techniques such that the sites pose minimal hazard to the public. EFSEC approved Energy Northwest's site restoration plan on June 12, 1995. In February 2016, a Memorandum of Understanding for final restoration of Site 1 was signed between Energy Northwest and Bonneville Power Administration. Site restoration activities have been ongoing since that time, and most restoration activities have been completed. Completion of restoration will require completion of the closure of the Site 1 landfill. In FY 2024 the Site 1 landfill requirements were changed from an inert landfill to a special purpose landfill by EFSEC, which requires a revision to the site restoration plan. The revised site restoration plan is expected to be submitted to EFSEC in August 2024. Upon acceptance of the revised plan by EFSEC, Energy Northwest will continue the restoration activities with expected completion by the end of FY 2025.

Business Development Fund Interest in Northwest Open Access Network (NoaNet)

Through FY 2023, Energy Northwest, along with 9 other Washington State public entities, was a member of NoaNet, a Washington nonprofit mutual corporation. NoaNet was formed in February 2000 to provide broadband communications over public benefit fibers leased from Bonneville Power Administration throughout the Pacific Northwest. The network began commercial operation in January 2001. In FY 2024, Energy Northwest notified the other members of NoaNet that it was reducing its participation from a member to an affiliate.

While as a member of NoaNet as allowed by RCW 54.16, Energy Northwest guaranteed certain portions of NoaNet debt based on its proportionate membership share. In November 2020 NoaNet obtained bond funding for $25 million with $17.7 million outstanding in December 2023; EN backed this debt at 10%, which was based on Energy Northwest's membership share of 8.04% with a step-up provision of 25% of the membership share. In Calendar Year 2023 NoaNet met all the debt obligations through profitable operations. NoaNet reserves the right to assess the members to cover deficits from operations. There have been no assessments since 2011. Energy Northwest is not liable for future assessments due to reducing its participation.

NoaNet reported an increase in net position of $7.7 million for Calendar Year 2023. In accordance with GAAP, Energy Northwest did not record their proportionate share of these gains/losses.

Financial statements for NoaNet may be obtained by writing to: Northwest Open Access Network, Chief Financial Officer, 7195 Wagner Way, Suite 104, Gig Harbor, WA 98335.

Business Development Fund New Nuclear Feasibility Study

In FY 2024, the Energy Northwest Executive Board of Directors approved the commitment of up to $5.3 million of the BDF cash reserves to provide bridging funding to ensure that continued progress was made on the new nuclear feasibility study. Also, in FY 2024, the Energy Northwest BDF signed an agreement with Puget Sound Energy in which they agreed to pay up to $10 million towards the feasibility study. As of June 30, 2024, Puget Sound Energy had made payments totaling $7.5 million. (See Notes 1 and 15). In addition, in March 2024, Washington state legislators included a $25 million proviso in the states 2023-2025 supplemental capital budget to support the feasibility study. The Act was signed by the Governor of Washington in March. However, the funding comes from an account created by the Climate Commitment Act (Act), which is subject to a November 2024 ballot initiative to repeal the Act. If the Act is repealed, the budget proviso would have to be reintroduced in the legislature with an alternative funding source (see Note 1).

Other Litigation and Commitments

Energy Northwest is a party to various claims and legal actions arising in the normal course of business. The following is a discussion of certain litigation and claims to which Energy Northwest is a party:

Energy Northwest v. United States of America (DOE). On August 28, 2014, Energy Northwest and the United States entered into a Settlement Agreement ("Settlement Agreement") under Energy Northwest v. United States, No. 11-447C (Fed. Cl. filed July 7, 2011). In addition to settling litigation for the U.S. Department of Energy's ("DOE") continuing breach of contract for its failure to dispose of spent nuclear fuel and high-level radioactive waste, the Settlement Agreement provided that Energy Northwest could be reimbursed by the government for its allowable expenses, as defined in the Settlement Agreement, related to DOE's continued failure to accept used nuclear fuel under the Standard Contract Energy Northwest signed with DOE in

1983. The Settlement Agreement also settled the litigation filed by Energy Northwest in the U.S. Court of Federal Claims in July 2011 for damages incurred between September 1, 2006, and June 30, 2012, in the amount of $23.6 million. Energy Northwest received $48.7 million in 2011 under the first action that resulted in a Stipulation for Entry of Final Judgment in Favor of Plaintiff Energy Northwest which covered damages prior to September 1, 2006.

Under the Settlement Agreement, Energy Northwest is required to submit a claim for reimbursement to DOE annually for each year, fiscal year. The claim submission deadline is January 31st of the following calendar year. After submission, DOE has a set time to review and request additional information from Energy Northwest. At the end of the review period, Energy Northwest can accept DOE's determination and be paid the amount determined by DOE or Energy Northwest can reject the determination and proceed to binding arbitration.

The Settlement Agreement has been extended three times and currently covers costs incurred before December 31, 2025. Under the Settlement Agreement, Energy Northwest has submitted annual claims for Fiscal Years 2013 through June 2023 and has been reimbursed almost $95 million for storage-related costs.

Although some suits, claims and commitments are significant in amount, final disposition is not determinable. In the opinion of management, the outcome of such litigation, claims or commitments will not have a material adverse effect on the financial positions of the business units or Energy Northwest as a whole. The future annual cost of the business units, however, may either be increased or decreased as a result of the outcome of these matters.

NOTE 11 - Nuclear Fuels

Energy Northwest has a large volume of inventory to support future reactor operations that was purchased well below current published market valuation. The in-stock inventory is sufficient to meet current projected reactor requirement for Columbia Generating Station up to the 2033 refueling. Energy Northwest has two open contracts for supply of additional uranium, conversion, and enrichment services. A contract with Orano USA with deliveries scheduled in December 2024 and January 2025. The other contract is with Louisiana Enrichment Services, LLC for delivery of enrichment In July 2025. These additional deliveries will provide sufficient Inventory to satisfy the 2035 and 2037 refueling at current projected reactor requirement for Columbia Generating Station.

Energy Northwest has a contract with Global Nuclear Fuel - Americas LLC valued at $192.0 million for fuel fabrication services through FY 2027, Energy Northwest made the decision in May 2024 to exercise the two optional reloads to extend the contract through 2031. The delivery of new fuel assemblies coincides with each refueling outage year, with the refueling complete in June 2023 (R-26).

Energy Northwest has a contract with DOE that requires DOE to accept title and dispose of spent nuclear fuel. Although the courts have ruled that DOE had the obligation to accept title to spent nuclear fuel by January 31, 1998, currently, there is no known date established when DOE will fulfill this legal obligation and begin accepting spent nuclear fuel. On November 19, 2013, the D.C. Circuit Court ordered the DOE to submit to Congress a proposal to reduce the current waste disposal fee to zero, unless and until there is a viable disposal program. On January 3, 2014, the DOE filed a petition for rehearing which was denied by the D.C. Circuit Court on March 18, 2014. Also, on January 3, 2014, the DOE submitted a proposal to Congress to reduce the current waste disposal fee to zero. On May 9, 2014, the DOE notified Energy Northwest that the waste disposal fee will remain in effect through May 15, 2014, after which time the fee will be set to zero. Until such time as a new fee structure is in effect, Energy Northwest will not accrue any further costs related to waste disposal fees. When the fuel is placed in the reactor the fuel cost is amortized to operating based on quantity of heat produced for generation of electric energy. The amount moved to spent fuel for cooling decreased $103.2 million.

The current period operating expense for Columbia was $60.5 million, which consists of $54.9 million for amortization of fuel used in the reactor and $5.6 million of O&M expenses for the ISFSI and milestone O&M expenses for spent fuel multi-purpose canisters. There was no DOE spent fuel disposal charges.

Energy Northwest has an Independent Spent Fuel Storage Installation (ISFSI), which is a temporary dry cask storage facility to be used until DOE completes its plan for a national repository. ISFSI will store the spent fuel in commercially available dry storage casks on a concrete pad at the Columbia site. Spent fuel is transferred from the spent fuel pool to the ISFSI periodically to allow for future refueling. The next ISFSI loading campaign is scheduled for March of 2026 for a total of 8 casks.

NOTE 12 - Other Post-Employment Benefits

The following table represents the aggregate OPEB amounts for all plans subject to the requirements of GASB 75 for the year ended June 30, 2024 (in thousands):

OPEB Liabilities	$	24,453
Deferred Outflows of Resources		1,333
Deferred Inflows of Resources		4,003
OPEB Expense		926

Energy Northwest provides to its retirees employer subsidies for postemployment medical insurance benefits (OPEB) provided through the Public Employees Benefits Board (PEBB). The actual medical costs are paid through annual fees and premiums to the PEBB.

General Information about the OPEB Plan

Plan Description

The PEBB was created within the Washington State Health Care Authority to administer medical, dental and life insurance plans for public employees and retirees and their dependents as a single employer plan. Agency employees who end public employment are eligible to continue PEBB insurance coverage as a retiree if they retire under the public employees' retirement system and are vested in that system.

Benefits Provided

The Washington State Health Care Authority (HCA) administers PEBB plan benefits. For medical insurance coverage, the HCA has two claims pools: one covering employees and non-Medicare eligible retirees, and the other covering retirees enrolled in Medicare Parts A and B. Each participating employer pays a portion of the premiums for active employees. For retirees, participating employers provide two different subsidies: an explicit subsidy and an implicit subsidy.

The explicit subsidies are monthly amounts paid per post-65 retiree and spouse. As of the valuation date of June 30, 2022, the explicit subsidy for post-65 retirees and spouses is the lesser of $183 or 50% of the monthly premiums. The retirees and spouses currently pay the premium minus $183 when the premium is over $366 per month and pay half the premium when the premium is lower than $366.

The implicit medical subsidy is the difference between the total cost of medical benefits and the premiums. For pre-65 retirees and spouses, the retiree pays the full premium amount, but that amount is based on a pool that includes active employees. Active employees will tend to be younger and healthier than retirees on average, and therefore can be expected to have lower average health costs. For post-65 retirees and spouses, the retiree does not pay the full premium due to the subsidy discussed above.

Employees Covered by Benefit Terms

At June 30, 2023 (measurement date), the following employees were covered by the benefit terms:

Inactive employees or beneficiaries currently receiving benefit payments	534
Inactive employees entitled to but not yet receiving benefit payments	-
Active employees	1,010

Funding Policy

The plan is funded on a pay-as-you-go basis and there are no assets accumulating in a qualifying trust.

Contributions

The OPEB relationship between PEBB employers and their employees and retirees is not formalized in a contract or plan document. Rather, the benefits are provided in accordance with a substantive plan. A substantive plan is one in which the plan terms are understood by the employers and plan members. This understanding is based on communications between the employers and plan members and the historical pattern of practice with regard to the sharing of benefit costs.

Total OPEB Liability

Energy Northwest's total OPEB liability was measured as of June 30, 2023, and was determined by an actuarial valuation dated June 30, 2022.

The total OPEB liability was determined using the following actuarial assumptions and other inputs:

Methodolgy:	
Actuarial Cost Method	Entry Age Normal (Level Percent of Salary)
Assumptions:	
Discount Rate - Based on S&P Municipal Bond 20 Year High Grade Index	4.13%
Beginning of Measurement Year	4.00%
End of Measurement Year	4.13%
Projected Salary Changes	3.50%
	Plus Merit-Based Increases
Medical Care Trend	7.0% decreasing to 6.5%, then .10% per year down to 4.5% and level thereafter
Actuarial Assumptions - Based on experience study conducted in 2020 using Public Employees' Retirement System (PERS) experience from 2013-2018	
Mortality Assumptions - PubG.H-2010 mortality tables adjusted for future mortality improvements using the MP-2017 fully generational improvement scale.	
Inflation Rate	2.50%
Post Retirement Participation Percentage - 100% of active employees currently electing coverage. Upon exhaustion of HRA VEBA funds, 50% are assumed to self-pay premiums until reaching Medicare eligibility. 3% of covered retirees are assumed to let their coverage lapse each year, until Medicare eligibility.	
Percentage with Spouse Coverage	70.00%

Changes in the Total OPEB Liability

(in thousands)

Balance - July 1	$	24,751
Service Cost		745
Interest		972
Differences Between Expected and Actual Experience		-
Changes of Assumptions or Other Inputs		(356)
Benefit Payments		(1,659)
Total	$	24,453

Sensitivity of the Total OPEB Liability to Changes in the Healthcare Cost Trend Rate and Discount Rate

The following presents the total OPEB liability of Energy Northwest calculated using a discount rate and healthcare cost trend rates that are 1-percentage point lower or 1-percentage-point higher than the current discount rate and health care cost trend rates (in thousands):

		1% Decrease	Current Rate		1% Increase
Discount Rate	$	27,422	$24,453	$	21,971
Healthcare Cost Trend Rate		21,555	24,453		28,042

OPEB Expense and Deferred Outflows of Resources and Deferred Inflows of Resources Related to OPEB

Energy Northwest recognized OPEB expense for the years ended December 31 as follows (in thousands):

Service Cost	$	745
Interest Cost		972
Recognition of Assumption Changes		(739)
Recognition of Experience Gains and Losses		(52)
Total	$	926

At June 30, 2024, Energy Northwest reported deferred outflows of resources and deferred inflows of resources related to OPEB from the following sources (in thousands):

		Deferred Outflows of Resources		Deferred Inflows of Resources
Differences Between Expected and Actual Experience	$	-	$	260
Changes of Assumptions or Other Inputs		-		3,743
Contributions Subsequent to the Measurement Date		1,333		-
Total	$	1,333	$	4,003

Deferred outflows of resources resulting from payments subsequent to the measurement date will be recognized as a reduction of the total OPEB liability in the following year.

Other amounts reported as deferred outflows and deferred inflows of resources related to OPEB will be recognized in OPEB expense as follows:

Year Ending June 30		
2025	$	(790)
2026		(790)
2027		(790)
2028		(790)
2029		(790)
Thereafter		(53)
Total	$	(4,003)

NOTE 13 - Leases

Lessee:

Energy Northwest (EN) under the following business units Nine Canyon Wind Project, Business Development, Internal Service Fund, Packwood Lake Hydroelectric Project, Columbia Generating Station, and Nuclear Project No. 1, have several leasing arrangements, summarized below:

The Nine Canyon Wind Project entered into a lease agreement to lease land space for three-hundred eighteen months beginning July 2021. The lease terminates December 2047. Under the terms of the lease, EN pays an annual base fee of $42,400. The base fee will follow the fixed rent schedule outlined in the lease agreement. EN also pays a pro rata share of operating expenses which are not included in the measurement of the lease liability as they are variable in nature. EN paid $154 during the fiscal year towards those variable costs. On June 30, 2024, EN recognized a right to use asset of $741,592 and a lease liability of $749,789. During the fiscal year, EN recorded $31,557 in amortization expense and $19,555 in interest expense for the right to use the land space. EN used an incremental borrowing rate of 2.57% based on the true interest cost for the most recent bond debt issuance for the same time periods.

The Business Development fund entered into a sublease agreement to lease land space for forty-eight months beginning July 2021. The lease terminates August 2025. Under the terms of the lease, EN pays an annual base fee of $7,500, with a 3.0% increase for the immediately preceding Term or extension period. On June 30, 2024, EN recognized a right to use asset of $118,672 and a lease liability of $120,164. During the fiscal year, EN recorded $3,338 in amortization expense and $4,264 in interest expense for the right to use the land space. EN used an incremental borrowing rate of 2.57% based on the true interest cost for the most recent bond debt issuance for the same time periods.

The Internal Service Fund entered into a lease agreement to lease office space for thirty-six months beginning August

2023. The lease terminates July 2026. Under the terms of the lease, EN paid a monthly base fee of $3,679. On June 30, 2024, EN recognized a right to use asset of $87,625 and a lease liability of $88,717. During the fiscal year, EN recorded $38,898 in amortization expense and $3,243 in interest expense for the right to use the office space. EN used an incremental borrowing rate of 3.35% based on the true interest cost for the most recent bond debt issuance for the same time periods.

The Packwood Hydroelectric Project entered into a lease agreement to lease equipment for thirty months beginning July 2021. The lease terminates January 2024. The lease agreement was renewed for twelve months, resulting in a short-term lease. Under the terms of the lease, EN pays a monthly base fee of $917. EN also pays a pro rata share of operating expenses which are not included in the measurement of the lease liability as they are variable in nature. EN paid $175 during the fiscal year towards those variable costs. On June 30, 2024, EN recognized a right to use asset of $0 and a lease liability of $0. During the fiscal year, EN recorded $5,767 in amortization expense and $42 in interest expense for the right to use the equipment. EN used an incremental borrowing rate of 2.57% based on the true interest cost for the most recent bond debt issuance for the same time periods.

The Packwood Hydroelectric Project entered into a lease agreement to lease equipment for forty-nine months beginning April 2024. The lease terminates June 2028. Under the terms of the lease, EN pays a monthly base fee of $1,671. On June 30, 2024, EN recognized a right to use asset of $69,409 and a lease liability of $70,556. During the fiscal year, EN recorded $5,573 in amortization expense and $729 in interest expense for the right to use the equipment. EN used an incremental borrowing rate of 3.35% based on the true interest cost for the most recent bond debt issuance for the same time periods.

The Nuclear Project No.1 entered into a lease agreement to lease land space for three-hundred sixty-six months beginning July 2021. The lease terminates December 2052. Under the terms of the lease, EN pays an annual base fee of $67,500, with an increase every 5 years during the Initial Term of the lease. On June 30, 2024, EN recognized a right to use asset of $1,321,522 and a lease liability of $1,330,375. During the fiscal year, EN recorded $47,197 in amortization expense and $34,697 in interest expense for the right to use the land space. EN used an incremental borrowing rate of 2.57% based on the true interest cost for the most recent bond debt issuance for the same time periods.

Columbia Generating Station entered into a lease agreement to lease land space for three-hundred seventy-two months beginning July 2021. The lease terminates December 2043. Under the terms of the lease, EN pays an annual base fee of $65,000. EN also pays a pro rata share of operating expenses which are not included in the measurement of the lease liability as they are variable in nature. EN paid $200 during the fiscal year towards those variable costs. On June 30, 2024, EN recognized a right to use asset of $912,190 and a lease liability of $924,752. During the fiscal year, EN recorded $51,125 in amortization expense and $24,119 in interest expense for the right to use the land space. EN used an incremental discount rate of 2.57% based on the true interest cost for the most recent bond debt issuance for the same time periods.

Columbia Generating Station entered into a lease agreement to lease equipment for eighty-six months beginning July 2021. The lease terminates September 2028. Under the terms of the lease, EN pays a monthly base fee of $20,030. On June 30, 2024, EN recognized a right to use asset of $896,348 and a lease liability of $912,725. During the fiscal year, EN recorded $214,980 in amortization expense and $26,085 in interest expense for the right to use the equipment. EN used an incremental borrowing rate of 2.57% based on the true interest cost for the most recent bond debt issuance for the same time periods.

Columbia Generating Station entered into a lease agreement to lease equipment for one-hundred eleven months beginning November 2021. The lease terminates February 2031. Under the terms of the lease, EN pays a monthly base fee of $20,810, which is a fixed price for the duration of the performance period. EN also pays a pro rata share of operating expenses which are not included in the measurement of the lease liability as they are variable in nature. EN paid $2,474 during the fiscal year towards those variable costs. On June 30, 2024, EN recognized a right to use asset of $1,418,615 and a lease liability of $1,528,366. During the fiscal year, EN recorded $212,793 in amortization expense and $41,874 in interest expense for the right to use the equipment. EN used an incremental borrowing rate of 2.57% based on the true interest cost for the most recent bond debt issuance for the same time periods.

Columbia Generating Station entered into a lease agreement to lease equipment for fifty months beginning July 2021. The lease terminates August 2025. Under the terms of the lease, EN pays a monthly base fee of $20,490. EN does not have the option to terminate the lease at any time. On June 30, 2024, EN recognized a right to use asset of $270,531 and a lease liability of $282,299. During the fiscal year, EN recorded $234,040 in amortization expense and $10,094 in interest expense for the right to use the equipment. EN used an incremental borrowing rate of 2.57% based on the true interest cost for the most recent bond debt issuance for the same time periods.

Columbia Generating Station entered into a lease agreement to lease equipment for sixty months beginning

October 2021. The lease terminates September 2026. Under the terms of the lease, EN pays an annual base fee of $69,544. EN does have the option to terminate the lease at any time provided, which EN will not exercise. EN does anticipate that Columbia Generating Station will purchase the equipment at the end of the lease Term. On June 30, 2024, EN recognized a right to use asset of $192,484 and a lease liability of $236,241. During the fiscal year, EN recorded $85,548 in amortization expense and $6,574 in interest expense for the right to use the equipment. EN used an incremental borrowing rate of 2.57% based on the true interest cost for the most recent bond debt issuance for the same time periods.

Nine Canyon Wind Project

Fiscal Year Ended June 30	Principal	Interest
2025	$ 23	$ 19
2026	23	18
2027	24	18
2028	25	17
2029	25	16
2030-2034	137	72
2035-2039	156	52
2040-2044	177	30
2045-2048	160	6
Total	$ 750	$ 248

Business Development Fund

Fiscal Year Ended June 30	Principal	Interest
2025	$ 4	$ 3
2026	4	3
2027	5	3
2028	5	3
2029	5	2
2030-2034	26	11
2035-2039	30	7
2040-2044	34	3
2045-2048	7	-
Total	$ 120	$ 35

Internal Service Fund

Fiscal Year Ended June 30	Principal	Interest
2025	$ 42	$ 2
2026	43	1
2027	4	-
Total	$ 89	$ 3

Packwood Hydroelectric Project

Fiscal Year Ended June 30	Principal	Interest
2025	$ 18	$ 2
2026	19	1
2027	19	-
2028	15	-
Total	$ 71	$ 3

Nuclear Project No.1

Fiscal Year Ended June 30	Principal	Interest
2025	$ 33	$ 34
2026	34	33
2027	35	32
2028	36	31
2029	36	30
2030-2034	197	135
2035-2039	224	108
2040-2044	254	76
2045-2049	289	41
2050-2053	192	5
Total	$ 1,330	$ 525

Columbia Generating Station

Fiscal Year Ended June 30	Principal	Interest
2025	$ 778	$ 89
2026	592	70
2027	606	55
2028	511	42
2029	281	32
2030-2034	652	82
2035-2039	279	39
2040-2043	185	7
Total	$ 3,884	$ 416

Amortization Expenses (Dollars in thousands)

	Lessee activities	Balance at July 1, 2023	Additions	Deletions	Balance at June 30, 2024
Nine Canyon Wind Project Right to use assets	Office Space	$ -	$ -	$ -	$ -
	Land	836	-	-	836
	Equipment	-	-	-	-
	Building Space	-	-	-	-
Accumulated Amortization		(63)	(32)	-	(95)
Nine Canyon Wind Project Totals		$ 773	$ (32)	$ -	$ 741
Business Development Fund Right to use assets	Office Space	$ -	$ -	$ -	$ -
	Land	135	-	-	135
	Equipment	-	-	-	-
	Building Space	-	-	-	-
Accumulated Amortization		(11)	(6)	-	(17)
Business Development Fund Totals		$ 124	$ (6)	$ -	$ 118
Internal Service Fund Right to use assets	Office Space	$ -	$ 126	$ -	$ 126
	Land	-	-	-	-
	Equipment	-	-	-	-
	Building Space	-	-	-	-
Accumulated Amortization		-	(39)	-	(39)
Internal Service Fund Totals		$ -	$ 87	$ -	$ 87
Packwood Lake Hydroelectric Project Right to use assets	Office Space	$ -	$ -	$ -	$ -
	Land	-	-	-	-
	Equipment	28	75	(28)	75
	Building Space	-	-	-	-
Accumulated Amortization		(22)	(12)	28	(6)
Packwood Project Totals		$ 6	$ 63	$ -	$ 69
Nuclear Project No.1 Right to use assets	Office Space	$ -	$ -	$ -	$ -
	Land	1,458	-	-	1,458
	Equipment	-	-	-	-
	Building Space	74	-	(74)	-
Accumulated Amortization		(163)	(47)	74	(136)
Nuclear Project No.1 Totals		$ 1,369	$ (47)	$ -	$ 1,322
Columbia Generating Station Right to use assets	Office Space	$ -	$ -	$ -	$ -
	Land	1,068	-	-	1,068
	Equipment	4,999	-	-	4,999
	Building Space	-	-	-	-
Accumulated Amortization		(1,578)	(799)	-	(2,377)
Columbia Generating Station Totals		$ 4,489	$ (799)	$ -	$ 3,690

Lessor:

Energy Northwest owns a multipurpose building in the City of Richland, Benton County, Washington known as the Applied Process Engineering Laboratory (APEL) which provides leased space of laboratory, validation testing, development facilities and associated offices for research and development. There are five lease agreements associated with the APEL building.

The first agreement was entered into in February of 2021 with a 3-year lease term. Contract rent will be evaluated on the anniversary date based on the Consumers Price Index. At termination, the lessee must remove any alterations and restore the premises to its original condition unless the lessor agrees to leaving the improvements in place. During the fiscal year, Energy Northwest recognized (in thousands) $53 in lease revenue and $3 in interest income related to this agreement. On June 30, 2024, Energy Northwest recorded $59 in lease receivables and $57 in deferred inflows of resources for this arrangement. Energy Northwest uses an interest rate of 3.65%, based on the 2022 bond interest rate.

The second agreement was entered into in May of 2021. Contract rent will be evaluated on the anniversary date based on the Consumers Price Index. At termination, the lessee has the right to remove any alterations and shall restore the premises to its original condition. During the fiscal year, Energy Northwest recognized (in thousands) $163 in lease revenue and $2 in interest income related to this agreement. On June 30, 2024, Energy Northwest recorded $0 in lease receivables and $0 in deferred inflows of resources for this arrangement. Energy Northwest uses an interest rate of 3.65%, based on the 2022 bond interest rate.

The third agreement leases 1/3 rack space referred to as Co-location space in the APEL building. This lease agreement was modified and the lease standard was implemented on May 1, 2023, with a lease term extending to April 30, 2026. At termination the lessee agrees to return the premises to the same condition as existed prior to the commencement of the use. During the fiscal year, Energy Northwest recognized (in thousands) $2 in lease revenue and $0 in interest income related to this agreement. On June 30, 2024, Energy Northwest recorded $3 in lease receivables and $3 in deferred inflows of resources for this arrangement. Energy Northwest uses an interest rate of 3.65%, based on the 2022 bond interest rate.

The fourth agreement leases office and laboratory space. This lease agreement became material In July of 2023, with a lease term extending to November of 2025. Contract rent will be evaluated on the anniversary date based on the Consumers Price Index. At termination, any improvements or alterations become property of the lessor unless the lessor requires the lessee to remove any alterations and restore the premises to its original condition. During the fiscal year, Energy Northwest recognized (in thousands) $111 In lease revenue and $7 in interest income related to this agreement. On June 30, 2024, Energy Northwest recorded $167 in lease receivables and $162 in deferred inflows of resources for this arrangement. Energy Northwest uses an interest rate of 3.35%, based on the 2023 bond interest rate.

The fifth agreement was entered into in April of 2024. Contract rent will be evaluated on the anniversary date based on the Consumers Price Index. At termination, the lessee has the right to remove any alterations and shall restore the premises to its original condition. During the fiscal year, Energy Northwest recognized (in thousands) $34 in lease revenue and $2 in interest income related to this agreement. On June 30, 2024, Energy Northwest recorded $269 in lease receivables and $269 in deferred inflows of resources for this arrangement. Energy Northwest uses an interest rate of 3.35%, based on the 2023 bond interest rate.

Energy Northwest owns a Multi-Purpose Facility (MPF) in the City of Richland, Benton County, Washington which provides leased office space. There are two lease agreements associated with the MPF building.

The first agreement was entered into in July of 2019 with a 4-year lease term and contained 1 four-year option period and 2 two-year options periods which Energy Northwest believes is reasonably certain to renew. Contract rent will increase annually based on the Consumers Price Index with a 3% cap. During the fiscal year, Energy Northwest recognized (in thousands) $276 in lease revenue and $71 in interest income related to this agreement. On June 30, 2024, Energy Northwest recorded $2,009 in lease receivables and $1,933 in deferred inflows of resources for this arrangement. Energy Northwest uses an interest rate of 3.35%, based on the 2023 bond interest rate.

The second agreement was entered into in July of 2019 with a 4-year lease term and contained 1 four-year option period and 2 two-year option periods which Energy Northwest believes is reasonably certain to renew. Additional space was leased in July of 2023. Contract rent will increase annually based on the Consumers Price Index with a 3% cap. During the fiscal year, Energy Northwest recognized (in thousands) $190 in lease revenue and $48 in interest income related to this agreement. On June 30, 2024, Energy Northwest recorded $1,346 in lease receivables and $1,328 in deferred inflows of resources for this arrangement. Energy Northwest uses an interest rate of 3.35%, based on the 2023 bond interest rate.

Energy Northwest maintains a lease for the plot of land from the Department of Energy-Richland Operations located in Benton County, Washington. This agreement leases a portion of the property consisting of a room/cabinet space of approximately 92 square feet and space on the structure and such easements as are necessary for antennas. This agreement was entered into in June of 2019 with a 5-year lease term and contained 5 five-year option periods which Energy Northwest believes is reasonably certain to renew. Contract rent will increase 2.5% at the end of the initial lease term and 9% at each 5-year option renewal. During the fiscal year, Energy Northwest recognized (in thousands) $18 in lease revenue and $12 in interest income related to this agreement. On June 30, 2024, Energy Northwest recorded $461 in lease receivables and $447 in deferred inflows of resources for this arrangement. Energy Northwest uses an interest rate of 2.57%, based on the 2020 bond interest rate.

NOTE 14 - Subscription-Based information Technology Arrangements

Energy Northwest (EN) under the following business units Internal Service Fund and Columbia Generating Station, have several subscription-based information technology arrangements (SBITAs), summarized below:

The Internal Service Fund entered ten separate SBITA contracts beginning July 2022. The SBITA contracts are all related to software subscriptions that have terms ranging from sixteen months to sixty-eight months. Initial payments totaling (in thousands) $2,300 were made in July 2022. An incremental borrowing rate of 3.65% was applied to all the contracts, based on the true interest cost for the most recent bond debt issuance for the same time periods. The sixteen-month SBITA contract expired in FY 2024, leaving nine of the original separate SBITA contracts.

The Internal Service Fund entered a sixty-month SBITA contract beginning July 2023. The SBITA contract is related to a software subscription. An initial payment (in thousands) of $21 was made in July 2023. An incremental borrowing rate of 3.35% was applied, based on the true interest cost for the most recent bond debt issuance for the same time period.

The Internal Service Fund entered a fifty month SBITA contract beginning September 2023. The SBITA contract is related to a software subscription. An initial payment (in thousands) of $207 was made in September 2023. An incremental borrowing rate of 3.35% was applied, based on the true interest cost for the most recent bond debt issuance for the same time period.

The Internal Service Fund entered an eighty-five month SBITA contract beginning October 2023. The SBITA contract is related to a software subscription. An initial payment (in thousands) of $538 was made in October 2023. An incremental borrowing rate of 3.65% was applied, based on the true interest cost for the most recent bond debt issuance for the same time period.

Columbia Generating Station entered four separate SBITA contracts beginning July 2022. The SBITA contracts are all related to software subscriptions that have terms ranging from fifteen months to sixty-two months. Initial payments (in thousands) totaling $343 were made in July 2022. An incremental borrowing rate of 3.65% was applied to all the contracts, based on the true interest cost for the most recent bond debt issuance for the same time periods. The fifteen month SBITA contract expired in FY 2024, leaving three of the original SBITA contracts.

Columbia Generating Station entered a thirty-six month SBITA contract beginning January 2024. The SBITA contract is related to a software subscription. An initial payment (in thousands) of $72 was made in January 2024. An incremental borrowing rate of 3.35% was applied, based on the true interest cost for the most recent bond debt issuance for the same time period.

	Balance at July 1, 2023	Additions	Deletions	Balance at June 30, 2024
Internal Service Fund				
Right to use subscription assets	$ 3,871	$ 3,660	$ (41)	$ 7,490
Accumulated amortization	(1,604)	(2,080)	41	(3,643)
Internal Service Fund Totals	$ 2,267	$ 1,580	$ -	$ 3,847
Columbia Generating Station				
Right to use subscription assets	$ 531	$ 214	$ (118)	$ 627
Accumulated amortization	(207)	(169)	118	(258)
Columbia Generating Station Totals	$ 324	$ 45	$ -	$ 369

Internal Service Fund

Fiscal Year Ended June 30	Principal	Interest
2025	$ 539	$ 95
2026	468	78
2027	485	60
2028	503	42
2029	501	23
2030-2034	494	5
Total	$ 2,990	$ 303

Columbia Generating Station

Fiscal Year Ended June 30	Principal	Interest
2025	$ 143	$ 7
2026	97	2
2027	25	-
Total	$ 266	$ 9

NOTE 15 - Subsequent Events

In July 2024, the Energy Northwest Executive Board approved the formation of a limited liability company (LLC). The LLC will be named Energy Northwest New Nuclear LLC and will be wholly owned by Energy Northwest. The LLC objective is to obtain financing for a small modular reactor project and repay such financing under the applicable terms. The LLC will be able to enter into contracts for the construction, operation and sale of power from the project, dependent on receiving approval from the Energy Northwest Board of Directors. Before a new project can be developed, approval is required to be obtained from the Energy Northwest Board of Directors.

In August 2024, Energy Northwest received the final $2.5 million installment from Puget Sound Energy for the new nuclear feasibility study (see Notes 1 and 10).

Schedules of Required Supplementary Information (Unaudited)

Schedule of Energy Northwest's Proportionate Share of the Net Pension Liability (Dollars in thousands)

PERS 1

Measurement Date Ended June 30	2023	2022	2021	2020	2019	2018	2017	2016	2015	2014
Proportion of the net pension liability (asset)	0.85%	0.92%	0.99%	0.89%	1.02%	1.08%	1.13%	1.08%	1.24%	1.22%
Proportionate share of the net pension liability (asset)	$ 19,502	$ 25,530	$ 12,128	$ 31,376	$ 39,358	$ 48,192	$ 53,781	$ 58,147	$ 65,005	$ 61,291
Covered-employee payroll	$ 152,417	$ 150,964	$ 146,520	$ 134,853	$ 143,601	$ 143,282	$ 142,483	$ 128,944	$ 154,431	$ 144,597
Proportionate share of the net pension liability (asset) as a percentage of its covered-employee payroll	12.80%	16.91%	8.28%	23.27%	27.41%	33.63%	37.75%	45.09%	42.09%	42.39%
Plan fiduciary net position as a percentage of the total pension liability	80.16%	76.56%	88.74%	68.64%	67.12%	63.22%	61.24%	57.03%	59.10%	61.19%

PERS 2/3

Measurement Date Ended June 30	2023	2022	2021	2020	2019	2018	2017	2016	2015	2014
Proportion of the net pension liability (asset)	1.10%	1.20%	1.28%	1.16%	1.32%	1.38%	1.45%	1.38%	1.60%	1.55%
Proportionate share of the net pension liability (asset)	$ (45,190)	$ (44,440)	$ (127,200)	$ 14,795	$ 12,831	$ 23,584	$ 50,411	$ 69,510	$ 57,017	$ 31,410
Covered-employee payroll	$ 152,417	$ 150,964	$ 146,520	$ 134,852	$ 143,502	$ 143,015	$ 142,140	$ 128,634	$ 154,080	$ 144,158
Proportionate share of the net pension liability (asset) as a percentage of its covered-employee payroll	-29.65%	-29.44%	-86.81%	10.97%	8.94%	16.49%	35.47%	54.04%	37.00%	21.79%
Plan fiduciary net position as a percentage of the total pension liability	107.02%	106.73%	120.29%	97.22%	97.77%	95.77%	90.97%	85.82%	89.20%	93.29%

Schedule of Energy Northwest's Contributions (Dollars in thousands)

PERS 1

Fiscal year Ended June 30	2024	2023	2022	2021	2020	2019	2018	2017	2016	2015
Contractually Required Contribution	$ 4,494	$ 5,822	$ 5,619	$ 7,397	$ 6,441	$ 7,339	$ 7,213	$ 6,818	$ 6,141	$ 5,711
Contributions in Relation to the Contractually Required Contribution Subtotal	(4,494)	(5,822)	(5,619)	(7,397)	(6,441)	(7,339)	(7,213)	(6,818)	(6,141)	(5,711)
Contribution Deficiency (Excess)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Covered-Employee Payroll	$ 151,619	$ 152,417	$ 150,964	$ 152,720	$ 134,853	$ 143,601	$ 143,282	$ 142,483	$ 128,944	$ 154,431
Contributions as a Percentage of Covered Employee Payroll	2.96%	3.82%	3.72%	4.84%	4.78%	5.11%	5.03%	4.79%	4.76%	3.70%

PERS 2/3

Fiscal year Ended June 30	2023	2022	2021	2020	2019	2018	2017	2016	2015	2014
Contractually Required Contribution	$ 9,643	$ 9,694	$ 9,627	$ 12,095	$ 10,657	$ 10,789	$ 10,658	$ 8,862	$ 8,200	$ 7,108
Contributions in Relation to the Contractually Required Contribution	(9,643)	(9,694)	(9,627)	(12,095)	(10,657)	(10,789)	(10,658)	(8,862)	(8,200)	(7,108)
Contribution Deficiency (Excess)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Covered-Employee Payroll	$ 151,619	$ 152,417	$ 150,964	$ 152,720	$ 134,852	$ 143,502	$ 143,015	$ 142,140	$ 128,634	$ 154,080
Contributions as a Percentage of Covered Employee Payroll	6.36%	6.36%	6.38%	7.92%	7.90%	7.52%	7.45%	6.23%	6.37%	4.61%

Notes to Schedules Key valuation assumptions:

- DRS allocates certain portion of contributions from PERS Plan 2/3 to PERS Plan 1 in order to fund its unfunded actuarially accrued liability (UAAL).
- There were no changes in actuarial assumptions between the valuation date of June 30, 2014 and the measurement date of June 30, 2015.
- There were no changes in actuarial assumptions between the valuation date of June 30, 2015 and the measurement date of June 30, 2016.
- There were no changes in actuarial assumptions between the valuation date of June 30, 2016 and the measurement date of June 30, 2017.
- There were no changes in actuarial assumptions between the valuation date of June 30, 2017 and the measurement date of June 30, 2018.
- There were changes in actuarial assumptions between the valuation date of June 30, 2018 and the measurement date of June 30, 2019.
    - Lowered the valuation interest rate from 7.70% to 7.50% for all plans.
    - Lowered the assumed general salary growth from 3.75% to 3.50% for all plans.
    - Lowered assumed inflation from 3.00% to 2.75% for all plans.
    - Lowered assumed investment rate of return from 7.50% to 7.40% for all plans.
- There were no changes in actuarial assumptions between the valuation date of June 30, 2019 and the measurement date of June 30, 2020.
- There were no changes in actuarial assumptions between the valuation date of June 30, 2020 and the measurement date of June 30, 2021.
- There were no changes in actuarial assumptions between the valuation date of June 30, 2020 and the measurement date of June 30, 2022.
- There were changes in actuarial assumptions between the valuation date of June 30, 2021 and the measurement date of June 30, 2023.
    - Lowered the valuation interest rate from 7.5% to 7.00% for all plans.
    - Lowered the assumed general salary growth from 3.50% to 3.25% for all plans.
- There were no changes in actuarial assumptions between the valuation date of June 30, 2022 and the measurement date of June 30, 2024.

Schedules of Required Supplementary Information (Unaudited)

Schedule of the Energy Northwest's Changes in the Total OPEB Liability and Related Ratios (Dollars in thousands)

	PERS 1			
Measurement Date Ended June 30	2023	2022	2021	2020
Total OPEB Liability - Beginning	$ 24,751	$ 29,571	$ 29,254	$ 28,850
Service Cost	745	1,028	1,006	1,006
Interest	972	662	654	646
Differences Between Expected and Actual Experience	-	(363)	-	-
Changes of Assumptions or Other Inputs	(356)	(4,814)	-	-
Benefit Payments	(1,659)	(1,333)	(1,343)	(1,248)
Total OPEB Liability - Ending	$ 24,453	$ 24,751	$ 29,571	$ 29,254
Covered-Employee Payroll	$ 124,982	$ 115,381	$ 102,720	$ 113,576
Total OPEB Liability as a % of Covered-Employee Payroll	19.57%	21.45%	28.79%	25.76%

Notes to Schedules
No assets are accumulated in a trust that meets the criteria in paragraph 4 of GASB 75.
* Until a full 10-year trend is compiled, only information for those years available is presented.
Key valuation assumptions:

- There were changes in actuarial assumptions as of the valuation and measurement date of June 30, 2022.
    - Increased the valuation discount rate from 2.25% to 4.00%.
    - Health Care Trend assumption was changed to 7.00% decreasing to 6.50%, then decreasing by 0.10% per year down to 4.50%, and level thereafter.
    - Inflation rate was increased from 2.00% to 2.50%.
- There were no changes in actuarial assumptions as of the valuation and measurement date of June 30, 2023.

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PROPOSED FORM OF OPINIONS OF BOND COUNSEL
FOR THE SERIES 2025-A/B BONDS

Energy Northwest

J.P. Morgan Securities LLC

Wells Fargo Bank, National Association

BofA Securities, Inc.

We have acted as bond counsel to Energy Northwest, a municipal corporation and joint operating agency of the State of Washington (the "State"), created and existing under and pursuant to Chapter 43.52 of the Revised Code of Washington, as amended (the "Act"), in connection with the issuance of its [$258,890,000/$404,135,000/$173,185,000/$109,025,000] [Project 1/Columbia Generating Station/Project 3] Electric Revenue [and] [Refunding] Bonds, Series 2025-[A/B (Taxable)] (the "2025-[A/B (Taxable)] Bonds"). The 2025-[A/B (Taxable)] Bonds are authorized to be issued pursuant to (i) the Act, (ii) Resolution No. [835/1042/838] (the "Electric Revenue Bond Resolution"), adopted by the Executive Board of Energy Northwest (the "Executive Board") on [November 23, 1993/October 23, 1997], as amended, and (iii) a Supplemental Resolution adopted by the Executive Board on March 27, 2025 (the "Supplemental Resolution"). The Electric Revenue Bond Resolution and the Supplemental Resolution are hereinafter collectively referred to as the "Bond Resolutions." All capitalized terms used herein and not otherwise defined shall have the respective meanings ascribed thereto in the Bond Resolutions.

The 2025-[A/B (Taxable)] Bonds are subject to redemption prior to their stated maturities as provided in the Bond Resolutions. The 2025-[A/B (Taxable)] Bonds rank equally as to security and payment with all other Parity Debt.

Regarding questions of fact material to our opinion, we have relied on representations of Energy Northwest in the Bond Resolutions and in the certified proceedings and on other certifications of public officials and others furnished to us without undertaking to verify the same by independent investigation.

Based on the foregoing, we are of the opinion that, under existing law:

1. Energy Northwest is a municipal corporation and joint operating agency, duly created and existing under the laws of the State, including particularly the Act, having the right and power under the Act to acquire, construct, own and operate the Project, adopt the Bond Resolutions, issue the 2025-[A/B (Taxable)] Bonds and apply the proceeds of the 2025-[A/B (Taxable)] Bonds in accordance with the Supplemental Resolution.

2. The Bond Resolutions have been duly and lawfully adopted by Energy Northwest, are in full force and effect, are valid and binding upon Energy Northwest and are enforceable in accordance with their terms. Energy Northwest's covenants in the Bond Resolutions to deposit all revenue derived from the Project into the Revenue Fund and to pay principal of and interest on the 2025-[A/B (Taxable)] Bonds and other Parity Debt are valid and binding upon Energy Northwest and are enforceable in accordance with their terms.

3. The 2025-[A/B (Taxable)] Bonds have been duly and validly authorized and issued under the Act and the Bond Resolutions and constitute valid and binding special revenue obligations of Energy Northwest, enforceable in accordance with their terms and the terms of the Bond Resolutions. The 2025-[A/B (Taxable)] Bonds are payable solely from the revenues and other amounts pledged to such payment under the Bond Resolutions. The 2025-[A/B (Taxable)] Bonds are not a debt of the State or any political subdivision thereof (other than Energy Northwest), and neither the State nor any other political subdivision of the State is liable thereon.

The opinions above are qualified to the extent that the enforcement of the rights and remedies of the owners of the 2025-[A/B (Taxable)] Bonds may be limited by laws relating to bankruptcy, reorganization, insolvency, moratorium or other similar laws of general application affecting the rights of creditors, by the application of equitable principles and by the exercise of judicial discretion, and we express no opinion regarding the enforceability of provisions in the Bond Resolutions that provide for rights of indemnification.

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

Very truly yours,

FOSTER GARVEY P.C.

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PROPOSED FORM OF SUPPLEMENTAL OPINIONS OF BOND COUNSEL
FOR THE SERIES 2025-A/B BONDS

Energy Northwest

J.P. Morgan Securities LLC

Wells Fargo Bank, National Association

BofA Securities, Inc.

We have acted as bond counsel to Energy Northwest, a municipal corporation and joint operating agency of the State of Washington (the "State"), created and existing under and pursuant to Chapter 43.52 of the Revised Code of Washington, as amended (the "Act"), in connection with the issuance of its [$258,890,000/$404,135,000/$173,185,000/$109,025,000] [Project 1/Columbia Generating Station/Project 3] Electric Revenue [and] [Refunding] Bonds, Series 2025-[A/B (Taxable)] (the "2025-[A/B (Taxable)] Bonds"). The 2025-[A/B (Taxable)] Bonds are authorized to be issued pursuant to (i) the Act, (ii) Resolution No. [835/1042/838] (the "Electric Revenue Bond Resolution"), adopted by the Executive Board of Energy Northwest (the "Executive Board") on [November 23, 1993/October 23, 1997], as amended, and (iii) a Supplemental Resolution adopted by the Executive Board on March 27, 2025 (the "Supplemental Resolution"). The Electric Revenue Bond Resolution and the Supplemental Resolution are hereinafter collectively referred to as the "Bond Resolutions." All capitalized terms used herein and not otherwise defined shall have the respective meanings ascribed thereto in the Bond Resolutions.

In connection with the issuance of the 2025-[A/B (Taxable)] Bonds, Energy Northwest has requested that we examine the validity of the WPPSS No. [1/2/3] Project Net Billing Agreements (the "Net Billing Agreements") and the Project No. [1/2/3] Assignment Agreement, dated as of August 24, 1984 (the "Assignment Agreement") (collectively the "Agreements"), by and between Energy Northwest and the United States of America, Department of Energy, acting by and through the Administrator (the "Administrator") of the Bonneville Power Administration ("Bonneville").

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

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

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

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

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

(e) The Certificate of the General Counsel of Energy Northwest, dated the date hereof, certifying that (i) neither Energy Northwest nor, to the best of his knowledge, any other party thereto has taken any action to (1) repeal, modify or terminate the Net Billing Agreements or the Assignment Agreement or (2) repeal any proceeding authorizing the execution and delivery of any such Agreement and (ii) to the best of his knowledge, each such Agreement remains in full force and effect as of the date hereof;

(f) The Certificate of the Administrator, dated the date hereof, certifying that (i) neither the Administrator nor, to the best of his knowledge, any other party thereto has taken any action to (1) repeal, modify or terminate the Net Billing Agreements or the Assignment Agreement or (2) repeal any proceeding authorizing the execution and delivery of any such Agreement and (ii) to the best of his knowledge, each such Agreement remains in full force and effect as of the date hereof;

(g) Certified copies of the proceedings of Energy Northwest authorizing the execution and delivery of the Net Billing Agreements and the Assignment Agreement and such other documents, proceedings and matters relating to the authorization, execution and delivery of such Agreements by each of the parties thereto as we deemed relevant;

(h) The opinion of General Counsel to Bonneville, dated the date hereof, to the effect that, inter alia, (i) the office of Administrator was duly established and is validly existing under the Bonneville Act, (ii) the Administrator was duly authorized to execute and deliver the Net Billing Agreements and the Assignment Agreement, and (iii) each of the Net Billing Agreements and the Assignment Agreement has been duly authorized, executed and delivered by the Administrator and did not constitute a violation of or conflict with the provisions of applicable law;

(i) The decision of the United States Court of Appeals for the Ninth Circuit in *City of Springfield v. Washington Public Power Supply System, et al.*, 752 F.2d 1423 (9th Cir. 1985), *cert. denied*, 474 U.S. 1055 (1986) ("Springfield"); and

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

Based upon the foregoing and in reliance thereon and based on the assumptions, exceptions and conclusions listed below, we are of the opinion that each of the Net Billing Agreements (which as to Project 1 consists of only Sections 5(a), 5(b), 7, 10 and 13 thereof) and the Assignment Agreement is a legal and valid obligation of Energy Northwest, Bonneville and the Participants currently obligated under the Net Billing Agreements, enforceable against such parties in accordance with its terms.

The foregoing opinion is subject to the following limitations, qualifications, exceptions, and assumptions:

(A) In rendering the opinion as to the enforceability of the Net Billing Agreements as to the Participants, we have assumed the continued obligations of Bonneville, and performance by Bonneville of its obligations as therein stated, under the Net Billing Agreements and Assignment Agreement. The assumption in the preceding sentence does not limit or affect our opinion as to the enforceability of the Net Billing Agreements and Assignment Agreement against Bonneville.

(B) The enforceability of all such Agreements may be subject to (i) the valid exercise of sovereign state police powers; (ii) the limitations on legal remedies against the United States of America under Federal law now or hereafter enacted; (iii) applicable bankruptcy, insolvency, reorganization, moratorium and other similar laws or enactments now or hereafter enacted by any state or the Federal government affecting the enforcement of creditors' rights; and (iv) the unavailability of equitable remedies or the application of general principles of equity (regardless of whether enforcement is sought in a proceeding in equity or at law).

(C) In rendering this opinion, (a) we have assumed with your consent (1) the authenticity of all documents submitted to us as originals, the genuineness of all signatures, the legal capacity of natural persons, and the conformity to the originals of all documents submitted to us as copies; (2) the truth and accuracy of all representations set forth in the Certificates of the Office of General Counsel of Energy Northwest and the Administrator referred to above in paragraphs (e) and (f); and (3)(A) the due incorporation and valid organization and existence as a municipality, publicly owned utility or rural electric cooperative, as applicable, of each Participant, (B) the due authorization by such Participant of the requisite governmental or corporate action, as the case may be, and due execution and delivery of the Net Billing Agreement to which such Participant is a party and that all assignments of any Participant's obligations under the Net Billing Agreements were properly done, and (C) with respect to the Participant's obligations under the Net Billing Agreements, no violation of or conflict with the provisions of applicable law, and (b) we have, with your consent, relied on the opinion of General Counsel to Bonneville referred to above in paragraph (h) as to the matters described therein.

(D) The opinions expressed herein are qualified to the extent that the characterization of, and the enforceability of any rights or remedies in, the Agreements may be limited by concepts of materiality, reasonableness, good faith and fair dealing, and rules governing specific performance, injunctive relief, marshalling, subrogation and other equitable remedies, regardless of whether raised in a court of law or otherwise. The opinions expressed herein are based on an analysis of existing laws (including, but not limited to, the law that provides that Bonneville may make expenditures from the Bonneville Fund which have been included in Bonneville's budget submitted to Congress without further appropriation or fiscal year limitation), regulations, rulings and court decisions and cover certain matters not directly addressed by such authorities. Such opinions may be affected by actions taken or omitted or events occurring after the date hereof.

(E) We express no opinion with respect to any provision for a remedy which is determined to be in the nature of a penalty, forfeiture or punitive damages, or which would provide the claimant with a duplication of damage awards or cumulative remedy, or which waives the applicability of any rule requiring an election of remedies. We express no opinion with respect to the obligation of Bonneville or any Participant to pay any debt or other obligation related to the Project on an accelerated basis.

(F) Our opinions are subject to the context rule of interpretation of contracts, which provides that even though terms of a contract may be unambiguous, courts may admit extrinsic evidence to interpret the contract.

This letter has been prepared solely for your use in connection with the transactions contemplated by the Agreements and should not be quoted in whole or in part or otherwise be referred to nor be relied upon by, filed with or furnished to, any governmental agency or other person or entity (other than your legal and professional advisors) without the prior consent of this firm. No attorney-client relationship has existed or exists between our firm and Bonneville, the Participants or the Underwriters with respect to the subject matter hereof or by virtue of this opinion. This letter opinion speaks as of its date and we do not hereby undertake to update this letter opinion. The opinions expressed in this letter are limited to the matters set forth in this letter, and no other opinions should be inferred beyond the matters expressly stated.

Very truly yours,

FOSTER GARVEY P.C.

PROPOSED FORM OF OPINION OF SPECIAL TAX COUNSEL
FOR THE SERIES 2025-A/B BONDS

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

Energy Northwest

$258,890,000 Project 1 Electric Revenue Refunding Bonds, Series 2025-A
$404,135,000 Columbia Generating Station Electric Revenue and Refunding Bonds, Series 2025-A
$173,185,000 Project 3 Electric Revenue Refunding Bonds, Series 2025-A

$109,025,000 Columbia Generating Station Electric Revenue Bonds, Series 2025-B (Taxable)

Ladies and Gentlemen:

We have acted as Special Tax Counsel to the Bonneville Power Administration in connection with the issuance by Energy Northwest (formerly known as the Washington Public Power Supply System), a municipal corporation and joint operating agency of the State of Washington, of $258,890,000 aggregate principal amount of Project 1 Electric Revenue Refunding Bonds, Series 2025-A (the "Project 1 Series 2025-A Bonds"), $404,135,000 aggregate principal amount of Columbia Generating Station Electric Revenue and Refunding Bonds, Series 2025-A (the "Columbia Series 2025-A Bonds"), $173,185,000 aggregate principal amount of Project 3 Electric Revenue Refunding Bonds, Series 2025-A (the "Project 3 Series 2025-A Bonds," and together with the Project 1 Series 2025-A Bonds and the Columbia Series 2025-A Bonds, the "Series 2025-A Bonds"), and $109,025,000 aggregate principal amount of Columbia Generating Station Electric Revenue Bonds, Series 2025-B (Taxable) (the "Columbia Series 2025-B (Taxable) Bonds" or the "Series 2025-B (Taxable) Bonds").

The Project 1 2025-A Bonds are being issued pursuant to Chapter 43.52 of the Revised Code of Washington, as amended (the "Act"), and Resolution No. 835, adopted by Energy Northwest on November 23, 1993, as amended and supplemented, and a supplemental resolution adopted on March 27, 2025 (the "Project 1 Resolution"). The Project 1 Resolution provides that the Project 1 2025-A Bonds are being issued for the purpose of refunding certain outstanding bonds issued by Energy Northwest, and paying costs of issuing the Project 1 2025-A Bonds.

The Columbia 2025-A Bonds and the Columbia 2025-B (Taxable) Bonds are being issued pursuant to the Act and Resolution No. 1042, adopted by Energy Northwest on October 27, 1997, as amended and supplemented, and a supplemental resolution adopted on March 27, 2025 (the "Columbia Resolution"). The Columbia Resolution provides that the Columbia 2025-A Bonds are being issued for the purpose of paying costs of capital improvements to the Columbia Generating Station, refunding certain outstanding bonds issued by Energy Northwest, and paying costs of issuing the Columbia 2025-A Bonds. The Columbia Resolution provides that the Columbia 2025-B (Taxable) Bonds are being issued for the purpose of paying (directly or indirectly through repayment of a bond anticipation note) fuel related costs and costs of capital improvements to the Columbia Generating Station, and paying costs of issuing the Columbia 2025-A Bonds and the Columbia 2025-B (Taxable) Bonds.

The Project 3 2025-A Bonds are being issued pursuant to the Act, and Resolution No. 838, adopted by Energy Northwest on November 23, 1993, as amended and supplemented, and a supplemental resolution adopted on March 27, 2025 (the "Project 3 Resolution," and collectively with the Project 1 Resolution and the Columbia Resolution, the "Resolutions"). The Project 3 Resolution provides that the Project 3 2025-A Bonds are being issued for the purpose of refunding certain outstanding bonds issued by Energy Northwest, and paying costs of issuing the Project 3 2025-A Bonds.

In such connection, we have reviewed certified copies of the Resolutions; the Tax Matters Certificate executed and delivered by Energy Northwest on the date hereof and the Tax Matters Certificate executed and delivered by the Bonneville Power Administration on the date hereof (together, the "Tax Certificates"); the opinions of Foster Garvey P.C., as Bond Counsel, dated the date hereof (the "Bond Counsel Opinions"); additional certificates of Energy Northwest, the Bonneville Power Administration and others; and such other documents, opinions and matters to the extent we deemed necessary to render the opinions set forth herein. We also have reviewed the opinions of bond counsel to Energy Northwest delivered in connection with the issuance of notes and bonds refunded directly or indirectly by the Series 2025-A Bonds and the Series 2025-B (Taxable) Bonds (the "Prior Bond Counsel Opinions"), each of which speaks as of its dated date.

The opinions expressed herein are based on an analysis of existing laws, regulations, rulings and court decisions and cover certain matters not directly addressed by such authorities. Such opinions may be affected by actions taken or omitted or events occurring after original delivery of the Series 2025-A Bonds and the Series 2025-B (Taxable) Bonds on 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 original delivery of the Series 2025-A Bonds and the Series 2025-B (Taxable) Bonds on the date hereof. Accordingly, this letter speaks only as of its date and is not intended to, and may not, be relied upon or otherwise used in connection with any such actions, events or matters. Our engagement with respect to the Series 2025-A Bonds and the Series 2025-B (Taxable) Bonds has concluded with their issuance, and we disclaim any obligation to update this letter. We have assumed the genuineness of all documents and signatures provided to us and the due and legal execution and delivery of each such document by each party thereto and that each such document constitutes a valid and binding agreement of such party. 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 fifth paragraph hereof. Furthermore, we have assumed compliance with all covenants and agreements contained in the Resolutions and the Tax Certificates, including (without limitation) covenants and agreements compliance with which is necessary to assure that future actions, omissions or events will not cause interest on the Series 2025-A Bonds to be included in gross income for federal income tax purposes. We call attention to the fact that the rights and obligations under the Series 2025-A Bonds, the Series 2025-B (Taxable) Bonds, the Resolutions and the Tax Certificates and their enforceability may be subject to bankruptcy, insolvency, receivership, reorganization, arrangement, fraudulent conveyance, moratorium and other laws relating to or affecting creditors' rights, to the application of equitable principles, to the exercise of judicial discretion in appropriate cases and to the limitations on legal remedies against bodies politic and corporate of the State of Washington and against the Bonneville Power Administration. Finally, as Special Tax Counsel we undertake no responsibility for the accuracy, completeness or fairness of any portion of the Official Statement of Energy Northwest, dated April 30, 2025, relating to the Series 2025-A Bonds and the Series 2025-B (Taxable) Bonds, or other offering material relating to the Series 2025-A Bonds and the Series 2025-B (Taxable) Bonds and express no view with respect thereto.

We have, with your consent, assumed the correctness of the Bond Counsel Opinions with respect to the validity of the Series 2025-A Bonds and the Series 2025-B (Taxable) Bonds, and with respect to the due authorization and issuance of the Series 2025-A Bonds and the Series 2025-B (Taxable) Bonds. With your consent, we also have assumed the correctness of Prior Bond Counsel Opinions with respect to the validity and the due authorization and issuance of notes and bonds refunded directly or indirectly by the Series 2025-A Bonds and the Series 2025-B (Taxable) Bonds.

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

1. Interest on the Series 2025-A Bonds is excluded from gross income for federal income tax purposes under Title XIII of the Tax Reform Act of 1986, as amended (the "1986 Act"), Section 103 of the Internal Revenue Code of 1986, as amended (the "1986 Code") and Section 103 of the Internal Revenue Code of 1954, as amended (the "1954 Code").

2. Interest on the Series 2025-A Bonds is not a specific preference item for purposes of the federal individual alternative minimum tax. We observe that interest on the Series 2025-A Bonds included in adjusted financial statement income of certain corporations is not excluded from the federal corporate alternative minimum tax.

3. Interest on the Series 2025-B (Taxable) Bonds is not excluded from gross income for federal income tax purposes under Title XIII of the 1986 Act, Section 103 of the 1986 Code or Section 103 of the 1954 Code.

We express no opinion regarding other tax consequences related to the ownership or disposition of, or the amount, accrual or receipt of interest on, the Series 2025-A Bonds or the Series 2025-B (Taxable) Bonds.

Faithfully yours,

ORRICK, HERRINGTON & SUTCLIFFE LLP

ENERGY NORTHWEST
PARTICIPANT UTILITY SHARE OF
FISCAL YEAR 2025 BUDGETS

	Participant Utility	Project 1 Share	Columbia Share	Project 3 Share
	City of Albion, Idaho	0.004	0.016	0.003
	City of Bandon, Oregon	0.166	0.263	0.144
*	Public Utility District No. 1 of Benton County, Washington	4.965	5.350	4.295
	Benton Rural Electric Association, Washington	0.308	0.666	0.645
	Big Bend Electric Cooperative, Inc., Washington	0.179	1.610	0.374
	Blachly-Lane County Cooperative Electric Association, Oregon	0.234	0.272	0.491
	Blaine City Light, Washington	0.109	0.185	0.101
	City of Bonners Ferry, Idaho, Electric Department	0.115	0.182	0.099
	City of Burley, Idaho, Electric	0.179	0.694	0.155
	Canby Utility Board, Oregon	0.296	0.090	0.256
	City of Cascade Locks, Oregon	0.074	0.054	0.064
	Central Electric Cooperative, Inc., Oregon	0.462	0.586	0.966
	Central Lincoln People's Utility District, Oregon	4.169	4.017	3.607
*	City of Centralia, Washington, Electric Light Department	0.298	0.739	0.258
*	Public Utility District No. 1 of Chelan County, Washington	0.501		0.433
	City of Cheney, Washington, Light Department	0.511	0.539	0.442
*	Public Utility District No. 1 of Clallam County, Washington	1.157	1.769	1.001
*	Public Utility District No. 1 of Clark County, Washington	14.305	6.151	13.633
	Clatskanie People's Utility District, Oregon	0.418	1.996	0.530
	Clearwater Power Company, Idaho	0.274	0.775	0.573
	Columbia Basin Electric Cooperative, Inc., Oregon	0.161	0.673	0.338
	Columbia Power Cooperative Association, Oregon	0.042	0.143	0.088
	Columbia Rural Electric Association, Inc., Washington	0.621	0.761	1.298
	Consolidated Irrigation District No. 19, Washington	0.005		0.005
	Consumers Power, Inc., Oregon	1.068	0.453	2.242
	Coos-Curry Electric Cooperative, Inc., Oregon	0.232	1.634	0.781
	Town of Coulee Dam, Washington, Light Department	0.048	0.137	0.041
*	Public Utility District No. 1 of Cowlitz County, Washington	7.379	5.525	3.461
	City of Declo, Idaho	0.026	0.019	0.023
*	Public Utility District No. 1 of Douglas County, Washington	0.044		0.049
	Douglas Electric Cooperative, Inc., Oregon	0.331	0.363	0.692
	City of Drain, Oregon, Light and Power	0.096	0.218	0.083
	East End Mutual Electric Company, Ltd., Idaho	0.011	0.033	0.023
	Town of Eatonville, Washington	0.010		
	City of Ellensburg, Washington	0.780	1.028	0.675
	Elmhurst Mutual Power and Light Co., Washington	0.170		
	Eugene Water & Electric Board, Oregon	0.061		
	Fall River Rural Electric Cooperative, Inc., Idaho	0.188	0.409	0.393
	Farmers Electric Co., Idaho	0.005	0.041	0.011
*	Public Utility District No. 1 of Ferry County, Washington	0.105	0.171	0.091
	City of Fircrest, Washington	0.423		
	Flathead Electric Cooperative, Inc., Montana	0.123	0.370	0.257

* Energy Northwest members.

	Participant Utility	Project 1 Share	Columbia Share	Project 3 Share
	City of Forest Grove, Oregon, Light and Power Department	0.470	0.181	0.091
*	Public Utility District No. 1 of Franklin County, Washington	1.330	2.370	1.151
	Glacier Electric Cooperative, Inc., Montana	0.098		
*	Public Utility District No. 2 of Grant County, Washington	0.486		0.420
*	Public Utility District No. 1 of Grays Harbor County, Washington	2.769	3.075	2.386
	Harney Electric Cooperative, Inc., Oregon	0.105	0.719	0.221
	City of Heyburn, Idaho	0.167	0.504	0.145
	Hood River Electric Cooperative, Oregon	0.224	0.502	0.469
	Idaho County Light and Power Cooperative Association, Inc., Idaho	0.047	0.186	0.098
	City of Idaho Falls, Idaho, Electric Division	0.908	2.376	0.787
	Inland Power & Light Company, Washington	0.907	1.222	1.915
*	Public Utility District No. 1 of Kittitas County, Washington	0.238	0.220	0.206
*	Public Utility District No. 1 of Klickitat County, Washington	0.517	1.009	0.448
	Kootenai Electric Cooperative, Inc., Idaho	0.212	0.391	0.443
	Lakeview Light and Power Company, Washington	0.168		
	Lane Electric Cooperative, Inc., Oregon	0.537	1.452	1.123
*	Public Utility District No. 1 of Lewis County, Washington	1.276	2.274	1.103
	Lincoln Electric Cooperative, Inc., Montana	0.087	0.255	0.182
	Lost River Electric Cooperative, Inc., Idaho	0.056	0.202	0.118
	Lower Valley Power and Light, Inc., Wyoming	0.266	0.820	0.557
*	Public Utility District No. 1 of Mason County, Washington	0.186	0.231	0.161
*	Public Utility District No. 3 of Mason County, Washington	1.274	1.446	1.265
	Town of McCleary, Washington	0.069	0.234	0.059
	McMinnville Water and Light, Oregon	1.141	1.227	0.547
	Midstate Electric Cooperative, Inc., Oregon	0.336	0.488	0.704
	City of Milton, Washington	0.027		
	Milton-Freewater Light and Power, Oregon	0.238	0.583	0.002
	City of Minidoka, Idaho	0.001	0.005	0.001
	Missoula Electric Cooperative, Inc., Montana	0.168	0.294	0.352
	City of Monmouth, Oregon	0.679	0.236	0.588
	Nespelem Valley Electric Cooperative, Inc., Washington	0.059	0.149	0.123
	Northern Lights, Inc., Idaho	0.234	0.455	0.489
	Northern Wasco County People's Utility District, Oregon	0.246	0.051	0.213
	Ohop Mutual Light Company, Washington	0.027		
	Okanogan County Electric Cooperative, Inc., Washington	0.038	0.190	0.079
*	Public Utility District No. 1 of Okanogan County, Washington	0.255	1.042	0.143
	Orcas Power and Light Company, Washington	0.257	0.725	0.733
*	Public Utility District No. 2 of Pacific County, Washington	1.006	1.503	0.870
	Parkland Light and Water Company, Washington	0.096		
*	Public Utility District No. 1 of Pend Oreille County, Washington	0.055		0.047
	Peninsula Light Company, Washington	0.261		
*	City of Port Angeles, Washington	0.665	2.416	0.576
	Raft River Rural Electric Cooperative, Inc., Idaho	0.224	0.853	0.468
	Ravalli County Electric Cooperative, Inc., Montana	0.195	0.301	0.409
*	City of Richland, Washington, Energy Service Department	1.828	2.780	1.592
	Riverside Electric Company, Idaho	0.007	0.020	0.015
	City of Rupert, Idaho, Electric Department	0.123	0.348	0.106

* Energy Northwest members.

	Participant Utility	Project 1 Share	Columbia Share	Project 3 Share
	Salem Electric, Oregon	0.662	0.453	1.385
	Salmon River Electric Cooperative, Inc., Idaho	0.046	0.170	0.097
*	City of Seattle, Washington, City Light Department	8.605	7.193	7.206
*	Public Utility District No. 1 of Skamania County, Washington	0.321	0.547	0.278
*	Public Utility District No. 1 of Snohomish County, Washington	19.584	15.363	19.334
	South Side Electric Lines, Inc., Idaho	0.032	0.073	0.067
	City of Springfield, Oregon, Utility Board	0.228	0.363	0.238
	Town of Steilacoom, Washington	0.038		
	City of Sumas, Washington	0.021	0.048	0.018
	Surprise Valley Electrification Corp., California	0.049	0.323	0.102
*	Tacoma Power, Washington	5.971		5.803
	Tanner Electric Cooperative, Washington	0.050	0.122	0.104
	Tillamook People's Utility District, Oregon	0.963	1.729	0.833
	Umatilla Electric Cooperative, Oregon	0.997	0.036	2.107
	United Electric Cooperative, Inc., Idaho	0.320	0.466	0.670
	Vera Water and Power, Washington	0.323	0.701	0.401
	Vigilante Electric Cooperative, Inc., Montana	0.042	0.294	0.088
*	Public Utility District No. 1 of Wahkiakum County, Washington	0.229	0.328	0.198
	Wasco Electric Cooperative, Inc., Oregon	0.116	0.342	0.244
	Wells Rural Electric Company, Nevada	0.102		0.214
	West Oregon Electric Cooperative, Inc., Oregon	0.121	0.182	0.252
*	Public Utility District No. 1 of Whatcom County, Washington	0.387		0.335
	TOTAL PARTICIPANT UTILITIES (111)	100.000	100.000	100.000

* Energy Northwest members.

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SUMMARY OF CERTAIN PROVISIONS OF RELATED CONTRACTS

The following summary of certain provisions of the Net Billing Agreements, the Project No. 2 Project Agreement (hereinafter referred to as the “Columbia Project Agreement”), and the Assignment Agreements does not purport to be complete. A copy of the foregoing agreements may be obtained from Energy Northwest. The capitalization of any word or words which are not conventionally capitalized indicates that such words are defined in the Net Billing Agreements.

THE NET BILLING AGREEMENTS

On February 6, 1973, Energy Northwest, Bonneville and each Project 1 Participant entered into a Project 1 Net Billing Agreement. As originally executed, the Project 1 Net Billing Agreements contained a description of Project 1, which included the use of the generating facilities which are a part of the Hanford Generating Project (“HGP”). Subsequently, on May 31, 1974, Energy Northwest, Bonneville and each Project 1 Participant entered into Amendatory Agreement No. 1 to each Project 1 Net Billing Agreement (the “Project 1 Amendatory Agreements”). Under the Project 1 Amendatory Agreements, among other things, the description of Project 1 was changed so that it no longer includes the use of HGP generating facilities. However, the provisions relating to the obligations incurred with respect to HGP after July 1, 1980 remain in effect.

On January 4, 1971, Energy Northwest, Bonneville and each Columbia Participant entered into a Columbia Net Billing Agreement.

On September 25, 1973, Energy Northwest, Bonneville and each Project 3 Participant entered into a Project 3 Net Billing Agreement.

Many of the provisions of the Net Billing Agreements have been summarized under the heading “SECURITY FOR THE NET BILLED BONDS — NET BILLING AND RELATED AGREEMENTS” in this Official Statement. A summary of certain additional provisions of the Net Billing Agreements, as amended, follows. Except where the text indicates otherwise, reference to Project 1 Net Billing Agreements is to such Agreements as amended by the Project 1 Amendatory Agreements. The summary describes the common features of, and highlights the differences among, the Net Billing Agreements for each of Project 1, Columbia and Project 3. Each of the Net Billing Agreements for the same Net Billed Project is identical except as to the Participants’ shares.

Term

Each Net Billing Agreement became effective upon its execution and delivery and will terminate as provided therein. See “Termination” below.

Although the Net Billing Agreements may be terminated prior to the maturity of the related Net Billed Bonds, the obligation of each of the Participants thereunder to pay its proportionate share of debt service on the related Net Billed Bonds shall continue until such Net Billed Bonds have been retired. Bonneville will continue to be obligated to offset or credit these payments against payments pursuant to the Participant’s contracts with Bonneville.

Project 1 and Project 3 have been terminated, and portions of the Project 1 and Project 3 Net Billing Agreements have been terminated. See “SECURITY FOR THE NET BILLED BONDS—NET BILLING AND RELATED AGREEMENTS—Payment Procedures” in this Official Statement.

Ownership and Operation

Energy Northwest covenants in the Columbia Net Billing Agreement to use its best efforts to arrange for the financing, design, construction, operation and maintenance of the Columbia Generating Station. Similar covenants of Energy Northwest under the Project 1 and Project 3 Net Billing Agreements terminated when the Board of Directors of Energy Northwest terminated Projects 1 and 3.

Sale, Purchase and Assignment

Under the Columbia Net Billing Agreements, Energy Northwest sells, and each Participant purchases, the Participant’s share of the Columbia Generating Station capability and each Participant in turn assigns its share of such capability to Bonneville. Such shares in the Columbia Generating Station for the fiscal year 2025 are shown in Appendix F in this Official Statement. Similar provisions in the Project 1 and Project 3 Net Billing Agreements terminated when the Board of Directors of Energy Northwest terminated Projects 1 and 3.

The provisions of the Net Billing Agreements with respect to payments are summarized under the heading “SECURITY FOR THE NET BILLED BONDS — NET BILLING AND RELATED AGREEMENTS” in this Official Statement.

If Bonneville is unable to satisfy its obligation to a Participant by net billing, assignment or cash payment and determines that this condition will continue for a significant period, the affected Participant may direct that all or a portion of the energy associated with its share of the Columbia Generating Station capability be delivered by Energy Northwest for the Participant’s account at a specified point of delivery, either for the expected period of such inability or the remainder of the term of the Columbia Net Billing Agreement, whichever is specified by the Participant when it elects to have such energy delivered to it. The amount of energy delivered will be limited to the amount of the Participant's share of the Columbia Generating Station capability for which payment by Bonneville cannot be made.

Energy Northwest Costs Payable Under Net Billing Agreements

All costs of Project 1, Columbia and Project 3 are payable under the respective Net Billing Agreements, and the Annual Budgets adopted by Energy Northwest shall make provision for all such costs, including accruals and amortizations, resulting from the ownership, operation (including cost of fuel), and maintenance of Project 1, Columbia and Project 3 and repairs, renewals, replacements, and additions to the Projects, including, but not limited to, the amounts which Energy Northwest is required under the Electric Revenue Bond Resolutions to pay into the various funds provided for in the resolutions for debt service and all other purposes. Each Participant is required to pay the amount specified in the Annual Budget, less amounts payable from sources other than payments under the Net Billing Agreements, multiplied by such Participant's share of Project capability.

Termination

If the Columbia Generating Station is ended pursuant to Section 15 of the Columbia Project Agreement, as described below under "THE PROJECT AGREEMENTS," Energy Northwest is required to give notice of termination of the Columbia Net Billing Agreement effective upon the date of termination of such Project Agreement. Energy Northwest will then terminate all activities relating to construction and operation of the Project and shall undertake the salvage and disposition or sale of such Project as provided in the Columbia Project Agreement.

In May 1994 the Board of Directors of Energy Northwest adopted a resolution which terminated Project 1 and a resolution requesting that the Project 3 Owners Committee declare the termination of Project 3. In June 1994 the Project 3 Owners Committee voted unanimously to terminate Project 3. In October 1998 Energy Northwest acquired all of the remaining assets of Project 3. Since that time, Energy Northwest has sold a portion of the Project 3 site to the Satsop Redevelopment Project and the balance of the site to Duke Energy Grays Harbor LLC. See "ENERGY NORTHWEST—PROJECT 1," "—PROJECT 3" and "—OTHER ACTIVITIES" and "SECURITY FOR THE NET BILLED BONDS—NET BILLING AND RELATED AGREEMENTS—Post Termination Agreements."

For a description of payments required to be made following termination of the Net Billing Agreements, see "SECURITY FOR THE NET BILLED BONDS—NET BILLING AND RELATED AGREEMENTS—Payment Procedures" in this Official Statement.

Modification and Assignment of Agreement

Each Net Billing Agreement provides that it shall not be amended, modified or otherwise changed by agreement of the parties thereto in any manner that will impair or adversely affect the security afforded by each Net Billing Agreement's provision for the payment of the principal, interest, and premium, if any, on the related Net Billed Bonds. The Net Billing Agreements further provide that, except for the reassignments of Participants' shares of Project capability provided for therein, no transfer or assignment of the Net Billing Agreements by any party thereto (except to the United States or an agency thereof) is permitted without the written consent of the other parties and that no assignment or transfer relieves the parties of any obligations thereunder.

Participants' Review Board

Each of the Net Billing Agreements for Columbia provides for the establishment of a Participants' Review Board consisting of nine members who are elected by the Participants in Columbia. Except in the event of an emergency requiring immediate action, copies of all bids, evaluations and proposed contracts and awards for amounts in excess of $500,000 shall be submitted to the Participant's Review Board. All Construction and Annual Budgets and fuel management plans, including amendments thereto, and plans for refinancing Columbia are required to be submitted by Energy Northwest to the Participants' Review Board within a reasonable time prior to the time such proposed budgets and plans are adopted by Energy Northwest.

The Net Billing Agreements provide that written recommendations of the Participants' Review Board shall be forwarded to Energy Northwest within a reasonable time and that Energy Northwest will consider such recommendations, giving due regard to Prudent Utility Practice and Energy Northwest's statutory duties. If Energy Northwest modifies or rejects a written recommendation of the Participants' Review Board, the Participants' Review Board may refer the matter to the Project Consultant in the manner described in the Project Agreement for his written decision and his decision shall be binding. Pending any such decision by the Project Consultant, Energy Northwest shall proceed in accordance with the Project Agreement. See "THE PROJECT AGREEMENTS—Term" hereinafter. The Net Billing Agreements provide that the provisions described above shall not affect the procedure for the settlement of any dispute between Bonneville and Energy Northwest under the Net Billing Agreements or the Project Agreement. See "THE PROJECT AGREEMENTS—Bonneville's Approval and Project Consultant" hereinafter in this Appendix G.

Prudent Utility Practice has the same meaning as is given in "THE PROJECT AGREEMENTS—Design, Licensing and Construction of the Project."

The Net Billing Agreements provide that, except as specifically provided in the Project Agreement, Energy Northwest shall not proceed with any item as proposed by it and not concurred in by Bonneville without approval of the Participants' Review Board.

THE PROJECT AGREEMENTS

On February 6, 1973, Energy Northwest and Bonneville entered into an agreement (the "Project 1 Project Agreement") which, among other things, provided standards for the design, licensing, financing, construction, fueling, operation and maintenance of Project 1, and for the making of any replacements, repairs or capital additions thereto. On May 31, 1974, Energy Northwest and Bonneville entered into Amendatory Agreement No. 1 to the Project 1 Project Agreement for the purpose of changing the description of Project 1 to conform to the changes made in the Project 1 Net Billing Agreements and to revise provisions relating to HGP.

On January 4, 1971, Energy Northwest and Bonneville entered into an agreement (the "Columbia Project Agreement") which, among other things, contains provisions with respect to the licensing, financing, construction, fueling, operation and maintenance of Columbia, and the making of any replacements, repairs or capital additions thereto, and budgeting under the Columbia Net Billing Agreements.

On September 25, 1973, Energy Northwest and Bonneville entered into an agreement (the "Project 3 Project Agreement" and, together with the Project 1 Project Agreement and the Columbia Project Agreement, the "Project Agreements") which, among other things, contained provisions with respect to the financing, construction, operation and maintenance of Project 3, and the making of any replacements, repairs or capital additions thereto, and budgeting under the Project 3 Net Billing Agreements.

Term

The Project 1 Project Agreement terminated as provided in Section 15 of the Project 1 Project Agreement in May 1994 when the Board of Directors of Energy Northwest adopted a resolution terminating Project 1.

The Columbia Project Agreement became effective upon its execution and delivery and will terminate as follows:

Columbia shall terminate and Energy Northwest shall cause Columbia to be salvaged, discontinued, decommissioned and disposed of or sold, in whole or in part, to the highest bidder or bidders, or disposed of in such other manner as the parties may agree when:

(a) Energy Northwest determines that it is unable to construct, operate, or proceed as owner of Columbia due to licensing, financing, or operating conditions or other causes which are beyond its control,

(b) The parties determine that Columbia is not capable of producing energy consistent with Prudent Utility Practice, or, if the parties disagree, the Project Consultant so determines, or

(c) Bonneville directs the end of Columbia pursuant to the provisions of the Columbia Project Agreement, which provides that if the estimated cost of a replacement or repair or capital addition required by a governmental agency after the date of commercial operation exceeds 20% of the then depreciated value of Columbia, Bonneville may direct that Energy Northwest end Columbia in accordance with Section 15.

In May 1994 the Board of Directors of Energy Northwest adopted a resolution requesting that the Project 3 Owners Committee declare the termination of Project 3. The Project 3 Owners Committee voted unanimously to terminate Project 3 and the Project 3 Project Agreement terminated in June 1994.

Design, Licensing and Construction of the Project

In the Columbia Project Agreement, Energy Northwest agrees, among other things, (i) to perform its duties and exercise its rights under such agreement in accordance with Prudent Utility Practice; (ii) to use its best efforts to obtain all licenses, permits and other rights and regulatory approvals necessary for the ownership, construction, and operation of the Project; (iii) to construct the Project in accordance with Prudent Utility Practice; and (iv) to keep Bonneville informed of all significant matters with respect to planning and construction of the Project.

"Prudent Utility Practice," as defined in the Columbia Project Agreement, at a particular time means any of the practices, methods and acts, including those engaged in or approved by a significant portion of the electrical utility industry prior to such time, which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, would have been expected to accomplish the desired result at the lowest reasonable cost consistent with reliability, safety and expedition. In evaluating whether any matter conforms to Prudent Utility Practice, Bonneville, Energy Northwest and any Project Consultant shall take into account the fact that Energy Northwest is a municipal corporation with statutory duties and responsibilities and the objective to integrate the entire Project capability with the generating resources of the Federal System in order to achieve optimum utilization of the resources of that System taken as a whole and to achieve efficient and economical operation of that System.

Financing

Energy Northwest agrees in the Columbia Project Agreement to use its best efforts to issue and sell Columbia Net Billed Bonds (if such Bonds may then be legally issued and sold) to finance the costs of Columbia and of any capital additions, renewals, repairs, replacements or modifications to Columbia.

The Columbia Project Agreement also provides that Energy Northwest may, after submitting its financing proposal to Bonneville, or shall, if requested by Bonneville, authorize the issuance and sale of additional Columbia Net Billed Bonds to refund outstanding Columbia Net Billed Bonds in accordance with the Columbia Net Billed Resolution. A proposal to refund outstanding Columbia Net Billed Bonds is required to be referred to the Project Consultant if, in the judgment of Bonneville or Energy Northwest, no substantial benefits will be achieved by such refunding. See "Bonneville's Approval and Project Consultant" below.

Net Billed Resolutions and resolutions of Energy Northwest supplementing or amending the Net Billed Resolutions are subject to approval by Bonneville, and Bonneville has approved each Net Billed Resolution and each supplemental resolution.

Budgets

Separate Annual Budgets for the Net Billed Projects will be prepared annually. See "SECURITY FOR THE NET BILLED BONDS—NET BILLING AND RELATED AGREEMENTS—Payment Procedures." The Annual Budget and any amendment thereof are to be submitted to Bonneville for its approval. In the absence of any objection by Bonneville, the Annual Budget will become effective within 30 days after submittal, and within seven days in the case of any amendment thereof. Any item disapproved is required to be referred to the Project Consultant. See "Bonneville's Approval and Project Consultant" below.

Operation and Maintenance

Energy Northwest shall operate and maintain Columbia in accordance with Prudent Utility Practice and in accordance with the requirements of government agencies having jurisdiction.

Bonds for Replacements, Repairs and Capital Additions

If in any contract year the amounts in an Annual Budget relating to renewals, repairs, replacements and betterments and for capital additions necessary to achieve design capability or required by governmental agencies ("Amounts for Extraordinary Costs"), whether or not such amounts are costs of operation or costs of construction, exceed the amount of reserves, if any, maintained for such purpose pursuant to the Columbia Net Billed Resolutions plus the proceeds of insurance, if any, available by reason of loss or damage to Columbia, by the lesser of (1) $3,000,000, or (2) an amount by which the amount of Bonneville's estimate of the total of the net billing credits available in such contract year to the Participants in Columbia and the amounts of such reserves and insurance proceeds, if any, exceeds the Annual Budget for such contract year exclusive of Amounts for Extraordinary Costs, Energy Northwest is required to, in good faith, use its best efforts to issue and sell Columbia Net Billed Bonds to pay such excess.

Bonneville's Approval and Project Consultant

If a proposal submitted by Energy Northwest to Bonneville under any provision of the Columbia Project Agreement is not disapproved by Bonneville within the time specified or, if no time is specified, within seven days after receipt, the proposal is deemed approved. With certain exceptions specified in the Columbia Project Agreement (including Bonneville's right to approve a Net Billed Resolution and any supplemental resolutions), disapproval by Bonneville is required to be based solely on whether the proposal is consistent with Prudent Utility Practice.

If any proposal subject to approval by Bonneville is disapproved by Bonneville and an alternative proposal is suggested by Bonneville, Energy Northwest shall adopt such suggestion or, within seven days after receipt of such disapproval, shall appoint a Project Consultant acceptable to Bonneville to review the proposal. Proposals found by the Project Consultant to be consistent with Prudent Utility Practice shall become immediately effective. Proposals found by the Project Consultant to be inconsistent with Prudent Utility Practice shall be modified to conform to the recommendation of the Project Consultant or as the parties otherwise agree and shall become effective as and when modified. If any proposal referred to the Project Consultant has not been resolved and will affect the continuous operation of Columbia, Energy Northwest shall continue to operate Columbia and may proceed as proposed by Energy Northwest, or as proposed by Bonneville, or as modified by mutual agreement of Energy Northwest and Bonneville. If Energy Northwest proceeds with its proposal, and it is determined by the Project Consultant to be inconsistent with Prudent Utility Practice, Energy Northwest shall bear any net increase in the cost of construction or operation of Columbia resulting from such proposal without charge to Columbia to the extent such proposal is found by the Project Consultant to be inconsistent with Prudent Utility Practice.

ASSIGNMENT AGREEMENTS

In 1984 Energy Northwest and Bonneville executed Assignment Agreements for each of Project 1, Columbia and Project 3. The purpose of the Assignment Agreements is to assure that Bonneville receives the entire output of Project 1, Columbia, and Project 3, and to assure that Energy Northwest receives sufficient funds to pay all obligations incurred in connection with such Projects, including debt service.

The Assignment Agreements provide that, subject only to the Participants' rights under the Net Billing Agreements, Energy Northwest assigns to Bonneville any rights which it now has or may hereafter obtain in project capability by a reversion of any Participant's share in Project capability to Energy Northwest or by any other means. Bonneville accepted this assignment, and in the event that any Participant is determined not to be obligated pursuant to the Net Billing Agreements to pay for any interest in Project capability which Bonneville obtains pursuant to the Assignment Agreements, Bonneville agrees to pay directly to Energy Northwest the amounts that would have been payable under the Net Billing Agreements for such Project capability.

The Assignment Agreements are designed to assure that Bonneville will obtain any interest Energy Northwest has or may hereafter obtain in Project capability, subject only to the Participants' rights and obligations under the Net Billing Agreements, and that the same economic and practical consequences will result for Bonneville and Energy Northwest as if Bonneville had acquired such interest in Project capability pursuant to the assignment of Project capability contained in the Net Billing Agreements.

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**SUMMARY OF CERTAIN PROVISIONS
OF THE ELECTRIC REVENUE BOND RESOLUTIONS
AND THE SUPPLEMENTAL ELECTRIC REVENUE BOND RESOLUTIONS**

The following summary is an outline of certain provisions contained in the Electric Revenue Bond Resolutions and the Supplemental Electric Revenue Bond Resolutions and is not to be considered as a full statement thereof. This summary is qualified by reference to and is subject to the Electric Revenue Bond Resolutions, copies of which may be examined at the principal offices of Energy Northwest and the Trustee. Capitalized terms not otherwise defined in this Appendix H shall have the meanings ascribed to them in this Official Statement.

Definitions

"*Authorized Purpose*" shall mean any one or more of the purposes described in Section 201 of the Electric Revenue Bond Resolutions.

"*Bank Bond*" shall mean any Electric Revenue Bond owned by the Related Credit Issuer or its permitted assigns in connection with the provision of moneys under the Related Credit Facility.

"*Code*" shall mean the Internal Revenue Code of 1986, as amended and supplemented from time to time, and the applicable temporary, proposed, or final regulations promulgated by the United States Treasury Department thereunder or under the Internal Revenue Code of 1954, as amended.

"*Credit Facility*" shall mean a letter of credit, line of credit, insurance policy, surety bond, standby bond purchase agreement or standby payment agreement or similar obligation or instrument or any combination of the foregoing issued by a bank, insurance company or similar financial institution or by the parent corporation of any of the foregoing or by the State or the Federal Government or any agency, authority, instrumentality or subdivision thereof, including, without limitation, the Administrator.

"*Debt Service Deposit Date*" shall mean any date on which a deposit is required to be made into the related Debt Service Fund by each Electric Revenue Bond Resolution or any Supplemental Electric Revenue Bond Resolution.

"*Defeasance Obligations*" shall mean (a) any of the obligations described in clause (i) of the definition of Investment Securities, (b) Refunded Municipal Obligations, and (c) with respect to any Series of Electric Revenue Bonds, such other obligations as are described in the Supplemental Electric Revenue Bond Resolutions authorizing such Series. The Supplemental Electric Revenue Bond Resolutions authorizing the Series 2025-A/B Bonds have additionally defined "Defeasance Obligations" to mean, with respect to the Series 2025-A/B Bonds, any "Government Obligations" as that term is defined in Chap. 39.53 RCW and as it may be hereafter amended.

"*Electric Revenue Bond Resolution*" shall mean Resolution No. 835, adopted on November 23, 1993, as amended and supplemented, Resolution No. 1042, adopted on October 23, 1997, as amended and supplemented, and Resolution No. 838, adopted on November 23, 1993, as amended and supplemented.

"*Engineer*" shall mean any nationally recognized independent engineer or engineering firm appointed by Energy Northwest.

"*Government Obligations*" means (a) direct obligations of, or obligations the principal of and interest on which are unconditionally guaranteed by the United States of America and bank certificates of deposit secured by such obligations; (b) bonds, debentures, notes, participation certificates, or other obligations issued by the banks for cooperatives, the federal intermediate credit bank, the federal home loan bank system, the export-import bank of the United States, federal land banks, or the federal national mortgage association; (c) public housing bonds and project notes fully secured by contracts with the United States; and (d) obligations of financial institutions insured by the federal deposit insurance corporation or the federal savings and loan insurance corporation, to the extent insured or to the extent guaranteed as permitted under any provision of state law, as such definition may be amended.

"*Investment Securities*" shall mean any of the following, if and to the extent that the same are legal for the investment of funds of Energy Northwest:

(i) direct obligations of, or obligations the principal of and interest on which are unconditionally guaranteed by, the United States of America;

(ii) obligations of any agency, subdivision, department, division or instrumentality of the United States of America, including, without limitation, the Federal Home Loan Mortgage Corporation, the Federal Agricultural Mortgage Corporation, the Student Loan Marketing Association and the International Bank for Reconstruction and Development; or obligations fully guaranteed as to interest and principal by any agency, subdivision, department, division or instrumentality of the United States of America;

(iii) direct obligations of, or obligations guaranteed as to principal and interest by, any state or direct obligations of any agency or public authority thereof, insured or uninsured, provided such obligations are rated, at the time of purchase, in one of the two highest rating categories by each rating agency then rating the Electric Revenue Bonds;

(iv) bank time deposits evidenced by certificates of deposit and bankers' acceptances issued by any bank or trust company (which may include the Trustee) which is a member of the Federal Deposit Insurance Corporation (or any successor thereto), provided that such time deposits and bankers' acceptances (a) do not exceed at any one time in the aggregate five percent (5%) of the total of the capital and surplus of such bank or trust company, or (b) are secured by obligations described in items (i) or (ii) of this definition of Investment Securities, which such obligations at all times have a market value at least equal to such time deposits so secured;

(v) repurchase agreements with (1) any bank or trust company (which may include the Trustee) which is a member of the Federal Deposit Insurance Corporation (or any successor thereto), or (2) any securities broker which is a member of the Securities Investor Protection Corporation, which such agreements are secured by securities which are obligations described in items (i) or (ii) of this definition of Investment Securities, provided that each such repurchase agreement (a) is in commercially reasonable form and is for a commercially reasonable period, and (b) results in transfer to the Trustee or Energy Northwest of legal title to, or the grant to the Trustee or Energy Northwest of a prior perfected security interest in, identified securities referred to in items (i) or (ii) of this definition which are free and clear of any claims by third parties and are segregated in a custodial or trust account held by a third party (other than the repurchaser) as the agent solely of, or in trust solely for the benefit of, the Trustee or Energy Northwest; provided that such securities acquired pursuant to such repurchase agreements shall be valued at the lower of the then current market value of such securities or the repurchase price thereof set forth in the applicable repurchase agreement;

(vi) certificates or other obligations that evidence ownership of the right to payments of principal of or interest on obligations of the United States of America or any state of the United States of America or any political subdivision thereof or any agency or instrumentality of the United States of America or any state or political subdivision, provided that such obligations shall be held in trust by a bank or trust company or a national banking association meeting the requirements for a Trustee under the Electric Revenue Bond Resolutions, and provided further that, in the case of certificates or other obligations that evidence ownership of the right to payments of principal or interest on obligations of a state or political subdivision, the payments of all principal of and interest on such certificates or such obligations shall be fully insured or unconditionally guaranteed by, or otherwise unconditionally payable pursuant to a credit support arrangement provided by, one or more financial institutions or insurance companies or associations which shall be rated in the highest rating category by each rating agency then rating the Electric Revenue Bonds or, in the case of an insurer providing municipal bond insurance policies insuring the payment, when due, of the principal of and interest on municipal bonds, such insurance policy shall result in such municipal bonds being rated in the highest rating category by each rating agency then rating the Electric Revenue Bonds;

(vii) investment agreements rated in one of the two highest rating categories by each rating agency then rating the Electric Revenue Bonds or the long-term unsecured debt obligations of the issuer of which are rated in one of the two highest rating categories by the respective agency rating such investment agreements or investment agreements which result in transfer to the Trustee or Energy Northwest of legal title to, or the grant to the Trustee or Energy Northwest of a prior perfected security interest in, identified securities referred to in items (i) or (ii) of this definition which are free and clear of any claims by third parties and are segregated in a custodial or trust account held by a third party (other than the counterparty to the investment agreement) as the agent solely of, or in trust solely for the benefit of, the Trustee or Energy Northwest;

(viii) bankers' acceptances drawn on and accepted or guaranteed by a commercial bank rated in either of the two highest rating categories by each rating agency then rating the Electric Revenue Bonds;

(ix) commercial paper rated, at the time of purchase, in the highest rating category by each rating agency then rating the Electric Revenue Bonds;

(x) shares of any publicly offered mutual fund of the type commonly known as a "money market fund" that, at the time of investment, has at least 85% of its assets directly invested in securities of the type described in items (i), (ii) and (iii) of this definition of Investment Securities; and

(xi) such other investments with respect to any Series of Electric Revenue Bonds as shall be specified in the Supplemental Electric Revenue Bond Resolution authorizing such Series of Electric Revenue Bonds.

"*Outstanding*" or "*outstanding*" shall mean, as if any date, (a) when used with reference to Electric Revenue Bonds, all Electric Revenue Bonds theretofore or thereupon issued or authorized pursuant to the Electric Revenue Bond Resolution, except: (i) any Electric Revenue Bonds paid in full, surrendered for cancellation or cancelled at or prior to such date (including any Bond held in escrow pending settlement of any tender offer by Energy Northwest or the Trustee on its behalf, but excluding any Option Bond so held pending settlement of a purchase on a tender date); and (ii) Electric Revenue Bonds in lieu of or in substitution for which other Electric Revenue Bonds shall have been authenticated or delivered pursuant to the Electric Revenue Bond Resolution; and (iii) Electric Revenue Bonds deemed to be no longer outstanding under the Electric Revenue Bond Resolution as provided therein or under any Supplemental Resolution authorizing the issuance of a Series of Electric Revenue Bonds, and (b) when used with reference to Subordinate Lien Obligations shall have the meaning assigned to such term by the instrument or instruments under which such Subordinate Lien Obligations are issued.

"*Parity Debt*" shall mean bonds, notes or other obligations issued under a resolution or resolutions authorized pursuant to the Electric Revenue Bond Resolutions, the Electric Revenue Bonds and any Parity Reimbursement Obligation.

"*Parity Reimbursement Obligation*" shall mean a reimbursement obligation the payment of which, pursuant to the provisions of a Supplemental Electric Revenue Bond Resolution, is secured as to payment by the pledge created by the Electric Revenue Bond Resolutions.

"*Payment Agreement*" shall mean a written agreement which provides for an exchange of payments based on interest rates, or for ceilings or floors on such payments, or an option on such payments, or any combination, entered into on either a current or forward basis.

"*Payment Date*" shall mean each date on which interest shall be due and payable and each date on which both interest shall be due and payable and a scheduled Principal Installment (whether by payment of principal scheduled to mature or a sinking fund installment to be paid) shall be required to be made on any of the outstanding Electric Revenue Bonds according to their respective terms.

"*Principal Installment*" shall mean, as of any date of calculation and with respect to any Series or Subseries, as the case may be, (a) the principal amount of Electric Revenue Bonds (including any amount designated in, or determined pursuant to, the applicable Supplemental Electric Revenue Bond Resolution, as the "principal amount" with respect to any bonds) of such Series or subseries scheduled to mature on a certain future date for which no sinking fund installments have been established, or (b) the unsatisfied balance of sinking fund installments scheduled to be paid on a certain future date for Electric Revenue Bonds of such Series or subseries, or (c) if such future dates coincide as to different Electric Revenue Bonds of such Series or subseries, the sum of such principal amount and such unsatisfied balance scheduled to mature or to be paid on such future date; in each case in the amounts and on the dates as provided in the applicable Supplemental Electric Revenue Bond Resolution authorizing such Series or subseries regardless of any retirement of Electric Revenue Bonds except pursuant to Section 505 of the Electric Revenue Bond Resolutions or (d) that portion of a Parity Reimbursement Obligation which corresponds to the amount of principal scheduled to mature or a sinking fund installment scheduled to be paid or that portion of a Parity Reimbursement Obligation payable on a certain future date which corresponds to the amount of principal scheduled to mature or a sinking fund installment scheduled to be paid.

"*Rating Agency*" shall mean Fitch, Inc. ("Fitch"), Moody's Ratings ("Moody's") or S&P Global Ratings ("S&P") or, if either Fitch, Moody's or S&P no longer furnishes ratings on a particular Series of the Electric Revenue Bonds, as the case may be, then such other nationally recognized rating agency then rating such Series of the Electric Revenue Bonds, as the case may be.

"*Refunded Municipal Obligations*" shall mean obligations of any state, the District of Columbia or possession of the United States of America or any political subdivision thereof, which obligations are rated in the highest rating category by at least two nationally recognized rating agencies and provision for the payment of the principal of and interest on which shall have been made by deposit with a Trustee or escrow agent of direct obligations of, or obligations guaranteed by, the United States of America, which are held by a bank or trust company organized and existing under the laws of the United States of America or any state, the District of Columbia or possession thereof in the capacity as custodian, the maturing principal of and interest on which when due and payable shall be sufficient to pay when due the principal of and interest on such obligations of such state, the District of Columbia, possession or political subdivision.

"*Reserve Account Requirement*" shall mean, with respect to a Series of Electric Revenue Bonds, the amount, if any, prescribed by the Supplemental Electric Revenue Bond Resolution authorizing such Series of Electric Revenue Bonds.

"*Reserve Guaranty*" shall mean an insurance policy or surety bond provided by an insurer whose claims-paying ability is rated in either of the two highest rating categories by at least two nationally recognized rating agencies, or a letter of credit or other similar Credit Facility the long-term unsecured debt of the issuer of which is rated in either of the two highest rating categories by at least two nationally recognized rating agencies.

"*Revenues*" shall mean all income, revenues, receipts and profits derived by Energy Northwest through the ownership and operation by Energy Northwest of the related Project and all other moneys required to be deposited in the Revenue Fund.

"*Subordinate Lien Obligation*" shall mean any bond, note, certificate, warrant or other evidence of indebtedness of Energy Northwest authorized by the Electric Revenue Bond Resolution.

Effect of Amendments Adopted March 9, 2001 (Project 1, Columbia and Project 3)

The Supplemental Resolutions adopted by the Executive Board of Energy Northwest on March 9, 2001, amend the Project 1, Columbia and Project 3 Electric Revenue Bond Resolutions, respectively, to add a covenant to the effect that, from and after the issuance of the Series 2001-A Bonds, Energy Northwest shall not otherwise create any other special fund or funds for the payment of bonds, warrants or other obligations which will rank on a parity with the pledge and lien on the Revenues created by any prior lien resolution.

Each Supplemental Resolution also amends the related Electric Revenue Bond Resolution to add a definition of the term "Energy Northwest" and to change the definition of the term "System," as follows:

"*Energy Northwest*" shall mean the joint operating agency organized and existing under the provisions of the Act and formerly known as the Washington Public Power Supply System.

"*System*" shall mean Energy Northwest.

The Project 1 Supplemental Resolution further amends the Project 1 Electric Revenue Bond Resolution to provide that all bonds, notes and other obligations, including without limitation Parity Debt initially issued by Energy Northwest under the Project 1 Electric Revenue Bond Resolution, from and after the date of adoption of the Project 1 Electric Revenue Bond Supplemental Resolution, including any bonds, notes or other obligations substituted or exchanged therefor from and after the adoption of such Project 1 Electric Revenue Bond Supplemental Resolution, shall be known as "Energy Northwest Project 1 Electric Revenue Bonds."

The Columbia Supplemental Resolution further amends the Columbia Electric Revenue Bond Resolution to provide that all bonds, notes and other obligations, including without limitation Parity Debt initially issued by Energy Northwest under the Columbia Electric Revenue Bond Resolution, from and after the date of adoption of the Columbia Electric Revenue Bond Supplemental Resolution, including any bonds, notes or other obligations substituted or exchanged therefor from and after the adoption of such Columbia Electric Revenue Bond Supplemental Resolution, shall be known, as "Energy Northwest Columbia Generating Station Electric Revenue Bonds."

The Project 3 Supplemental Resolution further amends the Project 3 Electric Revenue Bond Resolution to provide that all bonds, notes and other obligations, including without limitation Parity Debt initially issued by Energy Northwest under the Project 3 Electric Revenue Bond Resolution, from and after the date of adoption of the Project 3 Electric Revenue Bond Supplemental Resolution, including any bonds, notes or other obligations substituted or exchanged therefor from and after the adoption of such Project 3 Electric Revenue Bond Supplemental Resolution, shall be known, as "Energy Northwest Project 3 Electric Revenue Bonds."

Electric Revenue Bond Resolutions to Constitute Contract (Section 103)

Each Electric Revenue Bond Resolution constitutes a contract between Energy Northwest and the owners from time to time of the Electric Revenue Bonds, and the issuer of a Credit Facility, if any, relating to such subseries of Electric Revenue Bonds; and the pledge made in each related Electric Revenue Bond Resolution and the covenants and agreements therein set forth to be performed on behalf of Energy Northwest shall be for the equal benefit, protection and security of the owners of any and all of the Electric Revenue Bonds and the issuer of any related Credit Facility where the obligation of Energy Northwest to reimburse such issuer is a Parity Reimbursement Obligation, each of which, regardless of time or times of maturity or due dates, shall be of equal rank without preference, priority or distinction of the Electric Revenue Bonds over any other thereof except as expressly provided in or permitted by the Electric Revenue Bond Resolutions.

Authorization of Bonds (Section 201)

The Project 1 Electric Revenue Bond Resolution creates and establishes an issue of Electric Revenue Bonds of Energy Northwest known and designated as "Energy Northwest Project No. 1 Electric Revenue Bonds," the Columbia Electric Revenue Bond Resolution creates and establishes an issue of Electric Revenue Bonds of Energy Northwest known and designated as "Energy Northwest Columbia Electric Revenue Bonds," and the Project 3 Electric Revenue Bond Resolution creates and establishes an issue of Electric Revenue Bonds of Energy Northwest known and designated as "Energy Northwest Project No. 3 Electric Revenue Bonds."

The Electric Revenue Bonds may be issued under each Electric Revenue Bond Resolution from time to time in series, which may consist of two or more subseries, pursuant and subject to the terms, conditions and limitations of the Electric Revenue Bond Resolutions and any Supplemental Electric Revenue Bond Resolutions providing for the issuance of Electric Revenue Bonds, in such amounts as may be determined by Energy Northwest, for one or more of the following purposes: (i) refunding any Outstanding Electric Revenue Bond or any Outstanding Subordinate Lien Obligation; (ii) the payment, or reimbursement of Energy Northwest for the payment, of the costs of the acquisition, construction or installation of additional facilities or modifications to the related Project in compliance with the order or decision of any State or Federal agency or authority having competent jurisdiction; (iii) the payment, or the reimbursement of Energy Northwest for the payment, of all or a portion of the costs of making renewals, repairs, replacements, improvements or betterments to the related Project, including costs associated with the upgrading of the output capacity of the related Project, including expenses incurred in connection with the upgrading of any operating license in connection therewith; (iv) the payment, or the reimbursement of Energy Northwest for the payment, of all or a portion of the costs of capital additions, improvements or betterments to the related Project necessary to achieve design capability; (v) the payment, or the reimbursement of Energy Northwest for the payment, of all or a portion of the costs of (1) decommissioning the related Project or (2) restoring the site of the related Project, in compliance with applicable Federal or State law or any order or decision of any State or Federal agency or authority having competent jurisdiction; (vi) payment, or the reimbursement of Energy Northwest for the payment, of all or a portion of the costs of purchasing fuel for the related Project; (vii) providing funds for deposit into the Reserve Accounts or any other reserves established by any Supplemental Electric Revenue Bond Resolution for the payment of the principal of or interest on the Series of Electric Revenue Bonds authorized thereby and paying the costs incident to the issuance of such Series of Electric Revenue Bonds; and (viii) the payment, or the reimbursement of Energy Northwest for the payment, of the costs of any other purpose permitted by law.

Pledge Effected by the Electric Revenue Bond Resolutions (Section 202)

Energy Northwest pledges for the payment of the principal or redemption price of and interest on the Electric Revenue Bonds in accordance with their terms and the provisions of the Electric Revenue Bond Resolutions (i) the proceeds of the sale of the Electric Revenue Bonds pending application thereof in accordance with the provisions of the applicable Electric Revenue Bond Resolution or of any applicable Supplemental Electric Revenue Bond Resolution, (ii) subject to the provisions of each Electric Revenue Bond Resolution, all revenues, and (iii) the Debt Service Fund established by each Electric Revenue Bond Resolution, including the investments, if any, therein; provided, however, that, subject to each Electric Revenue Bond Resolution, amounts on deposit to the credit of any Reserve Account in the Debt Service Funds are pledged only to the Series of Electric Revenue Bonds for which such Reserve Account was established pursuant to the Supplemental Electric Revenue Bond Resolutions authorizing such Series and may be applied only to pay the principal or redemption price, if any, of and interest on the Electric Revenue Bonds of such Series.

Except as may be otherwise provided in the Electric Revenue Bond Resolutions or in the Supplemental Electric Revenue Bond Resolutions authorizing a Series of Electric Revenue Bonds, the Electric Revenue Bonds of each such Series shall be equally and ratably payable and secured under the related Electric Revenue Bond Resolution without priority by reason of the date of adoption of the Supplemental Electric Revenue Bond Resolutions providing for their issuance or by reason of their Series or subseries, number or date, date of issue, execution, authentication or sale thereof, or otherwise.

The revenues and other moneys pledged and received by Energy Northwest shall immediately be subject to the lien of the pledge made by Energy Northwest under each Supplemental Electric Revenue Bond Resolution without any physical delivery or further act, and the lien of the pledge shall be valid and binding as against any parties having claims of any kind in tort, contract or otherwise against Energy Northwest, irrespective of whether such parties have notice thereof.

Refunding Bonds (Section 204)

All Electric Revenue Bonds issued to refund Outstanding Electric Revenue Bonds shall be authenticated and delivered by the Trustee only upon receipt by it, in addition to other documents required by the Electric Revenue Bond Resolutions (and in addition to further documents required by the provisions of any Supplemental Electric Revenue Bond Resolutions), of:

(i) irrevocable instructions to the Trustee, satisfactory to it, to give due notice of redemption of all the Electric Revenue Bonds to be redeemed on a redemption date or dates specified in such instructions;

(ii) if the Electric Revenue Bonds to be refunded are not to be redeemed within the next succeeding 90 days, irrevocable instructions to the Trustee, satisfactory to it, to give due notice of any refunding of such Electric Revenue Bonds on a specified date prior to their maturity, as provided in Article VI of each Electric Revenue Bond Resolution or in the Supplemental Electric Revenue Bond Resolution which authorized such Electric Revenue Bonds to be refunded, and Section 1101 of each Electric Revenue Bond Resolution;

(iii) either (A) moneys (which may include all or a portion of the proceeds of the refunding Electric Revenue Bonds to be issued) in an amount sufficient to effect payment of the principal or the redemption price of the Electric Revenue Bonds to be refunded, together with accrued interest on such Electric Revenue Bonds to the maturity or redemption date thereof, as the case may be, or (B) Defeasance Obligations in such principal amounts, of such maturities, bearing such interest and otherwise having such terms and qualifications and any moneys, as shall be necessary to comply with the provisions of Section 1101 of each Electric Revenue Bond Resolution, which Defeasance Obligations and moneys shall be held in trust and used only as provided in Section 1101 of each Electric Revenue Bond Resolution; and

(iv) such further documents and moneys as are required by the provisions of each Electric Revenue Bond Resolution or any Electric Revenue Bond Supplemental Resolutions.

Subordinate Obligations (Section 205)

Nothing contained in the Electric Revenue Bond Resolutions prohibits or prevents Energy Northwest from authorizing and issuing bonds, notes, certificates, warrants or other evidences of any indebtedness for any purpose relating to the Net Billed Projects payable as to principal and interest from the revenues subject and subordinate to the deposits and credits required to be made to the funds established under the Electric Revenue Bond Resolutions or from securing such bonds, notes, certificates, warrants or other evidences of indebtedness and the payment thereof by a lien and pledge on the revenues junior and inferior to the lien and the pledge on the revenues created by the Electric Revenue Bond Resolutions.

Credit Facilities (Section 208)

Electric Revenue Bond Supplemental Resolutions providing for the issuance of a Series of Electric Revenue Bonds may provide that Energy Northwest obtain or cause to be obtained Credit Facilities providing for payment of all or a portion of the purchase price or Principal Installment or Redemption Price of, or interest due or to become due on specified Electric Revenue Bonds of such Series or any Subseries thereof, or providing for the purchase of such Electric Revenue Bonds or a portion thereof by the issuer of the Credit Facilities, or providing, in whole or in part, for the funding of the Reserve Accounts pursuant to Section 505 of each Electric Revenue Bond Resolution, provided such Credit Facility is a Reserve Guaranty. In connection therewith, Energy Northwest may enter into agreements with the issuers of the Credit Facility to provide for the terms and conditions thereof, including the security, if any, to be provided to such issuers.

Energy Northwest may secure the applicable Credit Facility by an agreement providing for the purchase of the Electric Revenue Bonds secured thereby with such adjustments to the rate of interest, method of determining interest, maturity, or redemption provisions as specified in the Supplemental Electric Revenue Bond Resolutions. Interest with respect to any Series of Electric Revenue Bonds so secured shall be calculated for purposes of the Reserve Account Requirement for such Series by using the actual rate of interest or, if applicable, the Certified Interest Rate on the Electric Revenue Bonds prior to adjustment under such agreement. Energy Northwest may also agree to reimburse directly the issuers of the Credit Facilities for any amounts paid thereunder together with interest thereon. Energy Northwest may provide that any such obligations to reimburse shall be Parity Reimbursement Obligations. In addition, Energy Northwest may, in connection with any such Credit Facility, agree to pay the fees and expenses of, and other amounts payable to, the issuers of such Credit Facilities, the payment of which may be secured by pledges of revenues, funds and other moneys pledged pursuant to the Electric Revenue Bond Resolutions on a parity with the pledges created by the Electric Revenue Bond Resolutions.

Establishment of Funds (Section 502)

The following special trust funds are established by each Electric Revenue Bond Resolution:

(a) General Revenue Fund, to be held and maintained by Energy Northwest; and

(b) Debt Service Fund, to be held and maintained by the Trustee. The Debt Service Fund shall include a separate Debt Service Account for each Series of Electric Revenue Bonds and a separate subaccount for each subseries of Electric Revenue Bonds issued under each Electric Revenue Bond Resolution and each such Debt Service Account and subaccount shall be designated using the designation of the Series or subseries, if any, to which such Debt Service Account or subaccount relates.

The existence of such funds shall be continued for so long as any Electric Revenue Bonds remain outstanding. Energy Northwest may establish pursuant to Supplemental Electric Revenue Bond Resolutions authorizing the issuance of Electric Revenue Bonds, additional funds, accounts and subaccounts for the purposes designated in such Supplemental Electric Revenue Bond Resolutions.

Disposition of Revenues (Section 503)

Energy Northwest covenants and agrees that it will pay into each General Revenue Fund as promptly as practical after receipt thereof all revenues and all other amounts required by the Electric Revenue Bond Resolutions to be so deposited.

General Revenue and Debt Service Funds (Sections 504 and 505)

General Revenue Fund. The amounts on deposit in each General Revenue Fund shall be trust funds in the hands of Energy Northwest and, subject to certain provisions described herein, shall be used and applied as provided in the applicable Electric Revenue Bond Resolution solely for the purpose of paying principal and interest on Parity Debt, the cost of operating and maintaining the related Project and paying all other costs, charges and expenses in connection with the costs of making repairs, renewals, replacements, additions, betterments and improvements to and extensions of the related Project and for purposes of paying all other charges and obligations against said revenues, income, receipts, profits and other moneys of whatever nature now or hereafter imposed thereon by law or contract, to the payment of which for such purposes said revenues and other moneys are pledged, including amounts required to be paid to the issuers of any Credit Facility pursuant to the provisions of any related Supplemental Electric Revenue Bond Resolution.

Energy Northwest shall pay, from the moneys on deposit in each General Revenue Fund, to each trustee or paying agent of Parity Debt (including the Trustee), and to each person entitled thereto in the event there is no trustee or paying agent for such Parity Debt, the respective stated amounts scheduled to be paid on such Parity Debt in accordance with its terms without preference or priority of any Parity Debt over any other Parity Debt, including the deposits into the Debt Service Accounts or subaccounts, as the case may be, hereinafter specified. In the event that the moneys on deposit in the General Revenue Fund shall be insufficient to make all payments required pursuant to the preceding sentence, Energy Northwest shall pay to each trustee or paying agent of Parity Debt and to each person thereof entitled thereto, as applicable, its pro rata share of the amounts on deposit in the General Revenue Fund. With respect to payments to be made to the Trustee, Energy Northwest shall set aside and pay (i) on or before the last Business Day in each month immediately preceding a Payment Date to the Trustee for deposit into the Debt Service Account for each Series, or, in the event a Series consists of two or more Subseries, into each relevant debt service subaccount in the related Debt Service Account, the amount, which, when added to the amount, if any, then on deposit in each respective Debt Service Account or subaccount thereof, as appropriate, will make the amount on deposit in each such Debt Service Account, or, with respect to Subseries, each subaccount thereof, equal to the amount of principal scheduled to mature, the amount of each sinking fund installment required to be paid, and the amount of interest due and payable, or, if such amount of interest is not known as of such date, the amount reasonably estimated by Energy Northwest to be necessary to pay interest on the Electric Revenue Bonds of each Series or Subseries on the next succeeding Payment Date, (ii) as and when required, the amounts required to be deposited in the accounts and subaccounts of the Debt Service Fund, and (iii) to the extent not included in clause (i) above, to the issuer of any Credit Facility and the counterparty to any Payment Agreement, and, with respect to any Parity Reimbursement Obligation, the amounts, if any, required to be so paid pursuant to the provisions of the related Supplemental Electric Revenue Bond Resolution, in each case, in the amounts, at the times and in the manner provided therein. There shall also be deposited in the Debt Service Fund and any accounts and subaccounts thereof, as and when received by the Trustee, all other amounts required by the applicable Electric Revenue Bond Resolution to be so deposited.

Debt Service Fund. The Trustee shall, for each Series or Subseries of Electric Revenue Bonds Outstanding, pay from the moneys on deposit in each relevant Debt Service Account or subaccount of each Debt Service Fund (i) the amounts required for the payment of the principal, if any, due on each Payment Date, (ii) the amount required for the payment of interest due on each Payment Date, (iii) on any redemption date the amounts required to pay the redemption price of the Electric Revenue Bonds to be redeemed on such date, unless the payment of such redemption price shall be otherwise provided, (iv) on any redemption date or date of purchase, the amounts required for the payment of accrued interest on Electric Revenue Bonds to be redeemed or purchased on such date unless the payment of such accrued interest shall be otherwise provided, and (v) at the times and in the manner provided in the related Supplemental Electric Revenue Bond Resolution and the agreements between Energy Northwest and any issuer of a Credit Facility or counterparty to any Payment Agreement, to the issuer of any Credit Facility and the counterparty to any Payment Agreement, and, with respect to any Parity Reimbursement Obligation, the amounts provided to be so paid.

Unless otherwise provided for a Series of Electric Revenue Bonds in the Supplemental Electric Revenue Bond Resolutions authorizing such Series, Energy Northwest may, prior to the forty-fifth day preceding the due date of any sinking fund installment purchase Electric Revenue Bonds of the Series or Subseries, as the case may be, and maturity for which such sinking fund installment was established, at prices (including any brokerage and other charges) not exceeding the redemption price payable for such Electric Revenue Bonds when such Electric Revenue Bonds are redeemable by application of such sinking fund installment plus unpaid interest accrued to the date of purchase, such purchases to be made by the Trustee as directed in writing by an authorized officer of Energy Northwest.

Unless otherwise provided for a Series of Electric Revenue Bonds in the Supplemental Electric Revenue Bond Resolutions authorizing such Series, upon the purchase or redemption (other than by application of sinking fund installments) of any Electric Revenue Bond, an amount equal to the principal amount of the Electric Revenue Bond so purchased or redeemed shall be credited toward the sinking fund installments thereafter to become due as directed in writing by an authorized officer of Energy Northwest.

Energy Northwest may, at its option, in lieu of depositing all or any part of the sinking fund installments into each relevant Debt Service Account or subaccount thereof of each Debt Service Fund, furnish the Trustee with a Certificate of an authorized officer stating that Energy Northwest has purchased for cancellation term bonds of a Series or Subseries of Electric Revenue Bonds in the principal amount, and bearing the numbers, specified therein, and that said term bonds have not been previously included in any such Certificate; and thereupon the sinking fund installments with respect to the term bonds of such Series or subseries, as the case may be, may be reduced by the principal amount of such term bonds canceled, as provided by such Certificate.

Unless otherwise provided for a Series of Electric Revenue Bonds or subseries thereof, as the case may be, in the Supplemental Electric Revenue Bond Resolutions authorizing such Series, as soon as practicable after the forty-fifth day preceding the due date of any such sinking fund installment, the Trustee shall proceed to call for redemption, pursuant to Article IV of each Electric Revenue Bond Resolution or the applicable Supplemental Electric Revenue Bond Resolutions, as the case may be, on such due date, Electric Revenue Bonds of the Series or subseries, as the case may be, and maturity for which such sinking fund installment was established in such amount as shall be necessary to complete the retirement of the principal amount specified for such sinking fund installment of the Electric Revenue Bonds of such Series or subseries, as the case may be, and maturity. The Trustee shall so call such Electric Revenue Bonds for redemption whether or not it then has moneys in each Debt Service Account or subaccount thereof of each Debt Service Fund established for such Series or subseries, as the case may be, sufficient to pay the applicable redemption price thereof on the redemption date. The Trustee shall apply to the redemption of the Electric Revenue Bonds on each such redemption date, the amount required for the redemption of such Electric Revenue Bonds.

Bond Proceeds Funds (Section 507)

The Supplemental Electric Revenue Bond Resolution providing for the issuance of any Series of Electric Revenue Bonds (exclusive of Refunding Bonds) will create and establish one or more special trust funds into which the proceeds of such Series of Electric Revenue Bonds will be deposited and from which such proceeds will be disbursed to pay the Costs of the Authorized Purpose or Purposes for which such Series of Electric Revenue Bonds were issued (unless such Supplemental Electric Revenue Bond Resolution will provide for the deposit of such proceeds in one or more of such funds theretofore created and established). Each such fund (a "Bond Proceeds Fund") will be held in trust by Energy Northwest, for the benefit of the owners of the Electric Revenue Bonds pending application thereof in accordance with the terms of the related Supplemental Electric Revenue Bond Resolution. Payments from Bond Proceeds Fund will be as specified in the Supplemental Electric Revenue Bond Resolution authorizing the issuance of a related Series of Electric Revenue Bonds.

Amounts on deposit in any Bond Proceeds Fund, pending their application as provided in the Supplemental Electric Revenue Bond Resolution creating such Bond Proceeds Fund, will be subject to a prior and paramount lien and charge in favor of the owners of the Electric Revenue Bonds, and the owners of the Electric Revenue Bonds will have a valid claim on such moneys for the further security of the Electric Revenue Bonds until paid out or transferred as herein provided.

Investment of Funds (Section 508)

Moneys held in each Debt Service Fund shall, to the fullest extent practicable and reasonable, be invested and reinvested by the Trustee upon request of Energy Northwest (promptly confirmed in writing) solely in Investment Securities which shall mature or be subject to redemption at the option of the owner thereof on or prior to the respective dates when the moneys therein will be required for the purposes intended. However, moneys in each Reserve Account in each Debt Service Fund not required for immediate disbursement for the purpose for which said Account is created shall, to the fullest extent practicable and reasonable, be invested and reinvested by the Trustee at the direction of Energy Northwest (promptly confirmed in writing) solely in, and obligations credited to each Reserve Account shall be, Investment Securities which, unless otherwise provided in the related Supplemental Electric Revenue Bond Resolution, shall mature or be subject to redemption at the option of the owner thereof on or prior to the last maturity date of the related Series of Electric Revenue Bonds. The Trustee shall not be liable for any depreciation in value of any such investments. For the purpose of Section 508 of the Electric Revenue Bond Resolutions, the term "Investment Securities" shall be limited to obligations described in clauses (i) and (v) of the definition of Investment Securities.

Nothing in the Electric Revenue Bond Resolutions shall prevent any Investment Securities acquired as investments of funds held thereunder from being issued or held in book-entry form.

Valuation or Sale of Investments (Section 509)

Investment Securities in any fund or account created under the provisions of each Electric Revenue Bond Resolution shall be deemed at all times to be part of such fund or account and any profit realized from the liquidation of such investment shall be credited to such fund or account and any loss resulting from liquidation of such investment shall be charged to such fund or account. Any such net profits or excess shall be transferred by the Trustee, without further authorization or direction by Energy Northwest, or paid to, or retained in, each General Revenue Fund.

In computing the amount in any fund or account, Investment Securities therein shall be valued at cost or, if purchased at a premium or discount, at their amortized value. Any such computation shall include accrued interest on the Investment Securities paid as part of the purchase price thereof and not repaid. Such computation shall be made annually on June 30th for all funds and accounts established pursuant to the Electric Revenue Bond Resolutions and at such other times as Energy Northwest shall determine or as may be required by the Electric Revenue Bond Resolutions.

Except as otherwise provided in the Electric Revenue Bond Resolutions, the Trustee, as directed by an authorized officer of Energy Northwest (promptly confirmed in writing), shall use its best efforts to sell at the best price obtainable, or present for redemption, any Investment Securities held by the Trustee in any fund or account whenever it shall be necessary, and upon oral request (promptly confirmed in writing) from an authorized officer of Energy Northwest in order to provide moneys to meet any payment or transfer from such fund or account. The Trustee shall not be liable or responsible for any loss resulting from any such investment, sale, liquidation or presentation for investment made in the manner provided above.

Subject to the foregoing limitations, any moneys held by Energy Northwest or the Trustee under a particular Electric Revenue Bond Resolution may be pooled in order to make any purchase of Investment Securities or deposit of moneys held under such Electric Revenue Bond Resolution, which purchases or deposits are otherwise permitted thereunder; provided, however, that Energy Northwest and the Trustee shall at all times keep accurate and complete records of the Investment Securities so purchased and deposits so made in sufficient detail as will permit the application of such Investment Securities and deposits, and the proceeds thereof, solely for the purposes, at the times and in the manner provided in each Electric Revenue Bond Resolution.

Qualifications and Appointment of Trustee; Resignation or Removal Thereof; Successor Thereto (Section 601)

In the Supplemental Electric Revenue Bond Resolution providing for the issuance of the initial Series of Electric Revenue Bonds, Energy Northwest shall appoint a Trustee (the "Trustee") to hold and administer the Funds and Accounts created and established in each Electric Revenue Bond Resolution. The Trustee will be a commercial bank with trust powers or trust company with capital stock, surplus and undivided profits aggregating in excess of $50,000,000. The Trustee may be removed at the request of or upon the affirmative vote of (i) the owners of a majority of the principal amount of Electric Revenue Bonds outstanding, or (ii) a majority of the members of the Executive Board of Energy Northwest, provided, however, that the Trustee may not be removed pursuant to the preceding clause (ii) upon the occurrence of an Event of Default or while such an Event of Default shall be continuing: provided further, that any removal will not take effect until the appointment of a successor and the acceptance by such successor in accordance with each Electric Revenue Bond Resolution.

In the event of the removal pursuant to clause (i) of the preceding sentence, resignation, disability or refusal to act of the Trustee, a successor may be appointed by the owners of a majority of the principal amount of Electric Revenue Bonds outstanding, excluding any Electric Revenue Bonds held by or for the account of Energy Northwest, and such successor shall have all the powers and obligations of the Trustee under each Electric Revenue Bond Resolution theretofore vested in its predecessor; provided, that unless a successor Trustee has been appointed by the owners of Electric Revenue Bonds as aforesaid, Energy Northwest by a duly executed written instrument signed by a majority of the members of the Executive Board will concurrently appoint a Trustee to fill such vacancy until a successor Trustee will be appointed by the owners of Electric Revenue Bonds as authorized in this paragraph. Any successor Trustee appointed by Energy Northwest pursuant to this paragraph will, immediately and without further act, be superseded by a Trustee so appointed by the owners of Electric Revenue Bonds.

In the event of the removal of the Trustee pursuant to clause (ii) above, Energy Northwest will appoint a successor Trustee.

Any Trustee may resign at any time by giving not less than 180 days' notice to Energy Northwest in writing and to the Bondholders by publishing a notice of resignation in an Authorized Newspaper once within 10 days after the giving of such notice to the Energy Northwest; provided, however, that such resignation shall not take effect until the appointment of a successor and the acceptance of such successor in accordance with this Resolution.

The resigning Trustee, if within 50 days after the publication of notice of its resignation no successor Trustee has been appointed and accepted such appointment, may petition any court of competent jurisdiction for the appointment of a successor Trustee, or any owner of a Bond who has been an owner of a Bond for at least six months may, on behalf of such owner and others similarly situated, petition any such court for the appointment of a successor Trustee. Such court may thereupon, after such notice, if any, appoint a successor Trustee having the qualifications required hereby.

In case at any time any of the following shall occur: (i) any Trustee ceases to be eligible in accordance with the provisions of each Electric Revenue Bond Resolution and fails to resign after written request therefor has been given to such Trustee by Energy Northwest or by any owner of a Bond who has been a bona fide owner of a Bond for at least six months, or (ii) any Trustee becomes incapable of acting, or is adjudged a bankrupt or insolvent, or a receiver of such Trustee or of its property is appointed, or any public officer takes charge or control of such Trustee or of its property or affairs for the purpose of rehabilitation, conservation or liquidation, or (iii) any Trustee neglects or fails in the performance of its duties under each Electric Revenue Bond Resolution, then, in any such case, Energy Northwest may remove such Trustee by an instrument in writing signed by an Authorized Officer or any such owner of a Bond may, on behalf of himself and all others similarly situated, petition any court of competent jurisdiction for the removal of such Trustee. Such court may thereupon, after such notice, if any, as it may deem proper and prescribe and as may be required by law, remove such Trustee.

Any successor Trustee shall meet the qualifications of each Electric Revenue Bond Resolution. Such successor Trustee will execute, acknowledge and deliver to its predecessor, and also to Energy Northwest, an instrument in writing accepting such appointment under each Electric Revenue Bond Resolution, and thereupon such successor Trustee, without any further acts, deed or conveyance, shall become fully vested with all the rights, powers, trusts, duties and obligations of its predecessor in trust under each Electric Revenue Bond Resolution, with like effect as if originally named as Trustee; but such predecessor will, nevertheless, on the written request of Energy Northwest or such successor Trustee, execute and deliver an instrument transferring to such successor Trustee all rights, powers, trusts, duties and obligations of such predecessor in trust under each Electric Revenue Bond Resolution and will deliver all moneys held by it to such successor Trustee, together with an accounting of funds held by it under each Electric Revenue Bond Resolution. The successor Trustee will have no responsibility for the acts of the predecessor Trustee.

Upon acceptance of appointment by the successor Trustee, as provided in this Section, Energy Northwest will publish notice of the succession of such Trustee to the trusts hereunder at least once in an Authorized Newspaper. If Energy Northwest fails to publish such notice, within 10 days after acceptance of appointment by the successor Trustee, the successor Trustee will cause such notice to be published at the expense of Energy Northwest.

Any corporation into which a Trustee may be merged or with which it may be consolidated, or any corporation resulting from any merger or consolidation to which a Trustee is a party, or any corporation to which a Trustee may sell or transfer all or substantially all of its corporate trust business, will be the successor Trustee under each Electric Revenue Bond Resolution without the execution or filing of any paper or any further act on the part of the parties to each Electric Revenue Bond Resolution; provided such corporation meets the qualifications of each Electric Revenue Bond Resolution.

Certain Covenants (Article VII)

Energy Northwest covenants and agrees with the purchasers and owners of all Electric Revenue Bonds issued pursuant to the Electric Revenue Bond Resolution to the following:

Concerning the Agreements. So long as any of the Electric Revenue Bonds are Outstanding, Energy Northwest will not (i) voluntarily consent to or permit any rescission of or consent to any amendment to or otherwise take any action under or in connection with any of the Net Billing Agreements which will reduce the payments provided for therein or which will in any manner impair or adversely affect the rights of Energy Northwest or of the owners from time to time of the Electric Revenue Bonds, or (ii) voluntarily consent to or permit any rescission of or consent to any amendment to or modification of or otherwise take any action under or in connection with, each Project Agreement in the case of Columbia, each Assignment Agreement, each Property Disposition Agreement or each 1989 Letter Agreement which will in any manner impair or adversely affect the rights of Energy Northwest or of the owners from time to time of the Electric Revenue Bonds; and Energy Northwest shall perform all of its obligations under said Agreements and shall take such actions and proceedings from time to time as shall be necessary to protect and safeguard the security for the payment of the Electric Revenue Bonds afforded by the provisions of said Agreements.

Encumbrance or Disposition of Project Properties; Termination of Projects. Energy Northwest will not sell, mortgage, lease or otherwise dispose of any properties of the related Project, or permit the sale, mortgage, lease or other disposition thereof, except as provided below.

(i) Energy Northwest may sell, lease or otherwise dispose of all or any portion of the works, plants and facilities of a Project and any real and personal property comprising a part thereof which is unserviceable, inadequate, obsolete, worn-out or unfit to be used or no longer required for use in connection with the operation of a Project, provided, however, that if the original costs of the properties so to be disposed of was in excess of $5,000,000, an Engineer shall first certify that the properties to be disposed of are unserviceable, inadequate, obsolete, worn-out or unfit to be used or no longer required for use in connection with the operations of a Project; provided, however, no such certification shall be required if such sale or other disposition takes place after a Project has been terminated. Money received by Energy Northwest as the proceeds of any such sale, lease or other disposition of all or any portion of the properties of a Project shall be used for the purchase or redemption of Electric Revenue Bonds and thereafter, any excess shall be deposited in the respective General Revenue Funds; provided, however, that if such sale, lease or other disposition of all or any portion of the properties of a Project is in connection with the replacement of such properties, all moneys received from such partial disposition of property may be transferred to the respective General Revenue Funds.

(ii) Energy Northwest may sell, lease or otherwise dispose of fuel for a price not less than the lesser of the cost to Energy Northwest thereof or the fair market value thereof at the time of such sale, lease or other disposition; provided, that any moneys received by Energy Northwest as proceeds of any such sale, lease or purchase shall be either transferred to the respective General Revenue Funds or used for the purchase or redemption of Electric Revenue Bonds.

(iii) In the event that the ownership of the properties of a Project or any part thereof shall be transferred from Energy Northwest through the operation of law, any moneys received by Energy Northwest as a result of any such transfer shall be used for the purchase or redemption of Electric Revenue Bonds and thereafter, any excess shall be deposited in the respective General Revenue Funds.

(iv) Energy Northwest may terminate a Project at any time. Any moneys received by Energy Northwest from the disposition of the properties of a Project so terminated may be applied to the payment of the cost of decommissioning such Project including the cost of restoring the site thereof, and any amounts so received not required to pay such costs shall be applied as provided in paragraph (iii) above or in each Electric Revenue Bond Resolution.

Nothing contained in the Electric Revenue Bond Resolutions shall be construed to prevent Energy Northwest from constructing as a separate utility system any additional generating unit or units on or near the site of any Project, and using facilities of a Project in connection with the construction or operation therewith without compensation therefor; provided, however, that an Engineer shall certify to Energy Northwest and the Trustee that such use will not adversely affect the operations of the applicable Project or interfere with the performance by Energy Northwest of its obligations under the Electric Revenue Bond Resolutions; and provided further, however, that any compensation received by Energy Northwest on account of any such use shall be paid into the respective General Revenue Funds.

Notwithstanding the provisions of subsections (i) through (iv) above, moneys received by Energy Northwest as a result of any sale, lease, transfer or other disposition specified in such subsections and which are in excess of the amounts required for decommissioning and site restoration costs may be transferred to such funds or accounts determined by Energy Northwest or used to purchase or redeem Electric Revenue Bonds.

Insurance. Energy Northwest shall, to the extent available at reasonable cost with responsible insurers, keep, or cause to be kept, the works, plants and facilities comprising the properties of the related Project and the operation thereof insured, with policies payable to Energy Northwest for the benefit of Energy Northwest, the Participants and Bonneville, as their interests may appear, against risks of direct physical loss, damage to or destruction of such properties or any part thereof, and against accidents, casualties, or negligence, including liability insurance and employer's liability, at least to the extent that similar insurance is usually carried by electric utilities operating like properties, and such other insurance as may be agreed upon by the parties to the Columbia Project Agreement. In the case of loss, including loss of revenue, caused by suspension or interruption of generation or transmission of power and energy by a Project, the proceeds of any insurance policy or policies covering such loss received by Energy Northwest shall be paid into the related General Revenue Fund. Within 60 days after the end of each fiscal year, Energy Northwest shall file, or cause to be filed, with the Trustee a certificate of an Engineer describing in reasonable detail the insurance on the Projects then in effect pursuant to the requirements of the related Electric Revenue Bond Resolution and stating whether, in its opinion, such insurance then in effect reasonably complies with the provisions hereof.

Books of Account; Annual Audit. Energy Northwest shall keep proper books of account for each Project, showing as a separate utility system the accounts of each Project in accordance with the rules and regulations prescribed by any governmental agency authorized to prescribe such rules, including the Division of Municipal Corporations of the State Auditor's office of the State of Washington, or other state department or agency succeeding to such duties of the State Auditor's office, and in accordance with the Uniform System of Accounts prescribed from time to time by the Federal Energy and Regulatory Commission, or any successor federal agency having jurisdiction over electric public utility companies owning and operating properties similar to each Project, whether or not Energy Northwest is required by law to use such system of accounts. Within 120 days after the end of each fiscal year, Energy Northwest shall cause such books of account to be audited by independent certified public accountants of national reputation licensed, registered or entitled to practice and practicing as such under the laws of the State of Washington who, or each of whom, is in fact independent and does not have any interest, direct or indirect, in any contract with Energy Northwest other than his contract of employment to audit books of account of Energy Northwest, and who is not connected with Energy Northwest as an officer or employee of Energy Northwest. A copy of each audit report, annual balance sheet and income and expense statement showing in reasonable detail the financial condition of each Project as of the close of each fiscal year and summarizing in reasonable detail the income and expenses for such year, including the transactions relating to the funds and accounts and the amounts expended for maintenance and for renewals, replacements and gross capital additions to each Project shall be filed promptly with the Trustee and sent to any Bondholder filing with Energy Northwest a written request for a copy thereof. In connection with each annual audit the independent auditor will prepare a report that states nothing came to their attention that caused them to believe that Energy Northwest failed to comply with the terms, covenants, provisions, or conditions of the Electric Revenue Bond Resolution and each Supplemental Electric Revenue Bond Resolution insofar as they relate to accounting matters or, if not in compliance therewith, the details of such failure to comply.

Consulting Engineer. So long as Energy Northwest owns and operates the Columbia Generating Station, Energy Northwest will retain on its staff one or more qualified engineers and hire an independent engineering firm when and as deemed necessary or advisable to provide immediate and continuous engineering counsel with respect to the Columbia Generating Station.

Protection of Security; Additional Parity Indebtedness. Energy Northwest is duly authorized under all applicable laws to create and issue the Electric Revenue Bonds and to adopt the Electric Revenue Bond Resolutions and to pledge the revenues and other moneys, securities and funds purported to be pledged by the Electric Revenue Bond Resolutions in the manner and to the extent provided in the Electric Revenue Bond Resolutions. The revenues and other moneys, securities and funds so pledged are and will be free and clear of any pledge, lien, charge or encumbrance thereon, or with respect thereto, prior to, or of equal rank with, the pledge created by the Electric Revenue Bond Resolutions. The Electric Revenue Bonds and the provisions of the Electric Revenue Bond Resolutions are and will be valid and legally enforceable obligations of Energy Northwest in accordance with their terms and the terms of the Electric Revenue Bond Resolutions. Energy Northwest shall at all times, to the extent permitted by law, defend, preserve and protect the pledge of the revenues and other moneys, securities and funds pledged under the Electric Revenue Bond Resolutions and all the rights of the Bondholders under the Electric Revenue Bond Resolutions or any issuer of a Credit Facility pursuant to a Supplemental Electric Revenue Bond Resolution against all claims and demands of all persons whomsoever.

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

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

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

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

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

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

Events of Default and Remedies (Section 801)

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

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

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

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

(4) if Energy Northwest shall fail to duly and punctually perform or observe any other of the covenants, agreements or conditions contained in the applicable Electric Revenue Bond Resolution or in the related Electric Revenue Bonds, on the part of Energy Northwest to be performed, and such failure shall continue for 90 days after written notice thereof from the Trustee or the owners of not less than 25% of the related Electric Revenue Bonds then outstanding; provided that, if such failure cannot be corrected within such 90 day period, it shall not constitute an Event of Default if corrective action is instituted within such period and diligently pursued until the failure is corrected;

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

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

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

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

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

Accounting and Examination of Records after Default (Section 803)

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

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

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

Energy Northwest covenants that if an Event of Default shall have happened and shall not have been remedied, upon demand of the Trustee, Energy Northwest shall pay over to the Trustee forthwith, all moneys, securities and funds, if any, then held by Energy Northwest and pledged under the related Electric Revenue Bond Resolution.

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

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

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

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

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

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

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

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

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

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

If and whenever all overdue installments of interest on all Electric Revenue Bonds and any related Parity Reimbursement Obligations and Other Parity Obligations, together with the reasonable and proper charges, expenses, and liabilities of the owners of the Electric Revenue Bonds or the obligees of such Parity Reimbursement Obligation or Other Parity Obligation, as applicable, their respective agents and attorneys, and all other sums payable by Energy Northwest under the related Electric Revenue Bond Resolution including the Principal Installment or redemption price of all Electric Revenue Bonds which shall then be payable, shall either be paid in full by or for the account of Energy Northwest or provision satisfactory to the Trustee shall be made for such payment, and all defaults under the applicable Electric Revenue Bond Resolutions or the related Electric Revenue Bonds shall be made good and secured to the satisfaction of the Trustee or provision deemed by the Trustee to be adequate therefor, the Trustee shall pay over to Energy Northwest all of its money, securities, funds and revenues then remaining unexpended in the hands of the Trustee (except moneys, securities, funds or revenues deposited or pledged, or required by the terms of the applicable Electric Revenue Bond Resolution to be deposited or pledged, with the Trustee), control of the business and possession of the property of the applicable Project shall be restored to Energy Northwest, and thereupon Energy Northwest and the Trustee shall be restored to their former positions and rights under the applicable Electric Revenue Bond Resolution, and all revenues shall thereafter be applied as provided in Article V of the applicable Electric Revenue Bond Resolution. No such payment to Energy Northwest by the Trustee or resumption of this application of revenues as provided in Article VI of the applicable Electric Revenue Bond Resolution shall extend to or affect any subsequent default under the applicable Electric Revenue Bond Resolution or impair any right consequent thereon.

Remedies Not Exclusive (Section 809)

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

Waivers of Default (Section 810)

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

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

Supplemental Electric Revenue Bond Resolutions (Article IX)

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

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

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

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

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

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

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

(7) to enter into Payment Agreements; and

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

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

Powers of Amendment (Section 1002)

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

Defeasance (Article XI)

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

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

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

At such time as an Electric Revenue Bond shall be deemed to be no longer outstanding under the related Electric Revenue Bond Resolution, such Electric Revenue Bond shall no longer be secured by or entitled to the benefits of the related Electric Revenue Bond Resolution, except for the purposes of any payment from such moneys or Defeasance Obligations.

Notwithstanding the foregoing, in the case of an Electric Revenue Bond which is to be redeemed or otherwise prepaid prior to its stated maturity, no deposit under clause (B) of subparagraph (ii) above shall constitute such payment, discharge and satisfaction as aforesaid until such Electric Revenue Bond shall have been irrevocably designated for redemption or prepayment and proper notice of such redemption or prepayment shall have been previously published in accordance with each Electric Revenue Bond Resolution or in accordance with the provisions of the Supplemental Electric Revenue Bond Resolutions which authorized the issuance of the Electric Revenue Bonds being refunded or provision satisfactory to the Trustee shall have been irrevocably made for the giving of such notice.

Any such moneys so deposited with the trustee or paying agents for the Electric Revenue Bonds as provided in the Electric Revenue Bond Resolutions may at the direction of Energy Northwest also be invested and reinvested in Defeasance Obligations, maturing in the amounts and times as hereinbefore set forth. All income from all Defeasance Obligations in the hands of the trustee or paying agents which is not required for the payment of the Electric Revenue Bonds and interest and premium thereon with respect to which such moneys shall have been so deposited, shall be paid to Energy Northwest for deposit in the respective General Revenue Funds. Likewise, whenever all of the Electric Revenue Bonds of a Series shall be deemed to be no longer outstanding under the related Electric Revenue Bond Resolution, as aforesaid, the amounts, if any, remaining on deposit to the credit of the Reserve Accounts established for such Series shall be paid to Energy Northwest for deposit in the respective General Revenue Funds.

Any provision contained in the Electric Revenue Bond Resolutions to the contrary notwithstanding, all moneys and Defeasance Obligations set aside and held in trust for the payment of Electric Revenue Bonds shall be applied to and used solely for the payment of the particular Electric Revenue Bond with respect to which such moneys and Defeasance Obligations have been so set aside in trust.

Notwithstanding anything in the Electric Revenue Bond Resolutions to the contrary, if moneys or Defeasance Obligations have been deposited or set aside with the trustee or a paying agent for the payment of a specific Electric Revenue Bond and such Electric Revenue Bond shall be deemed to have been paid and to be no longer outstanding, but such Electric Revenue Bond shall not have in fact been actually paid in full, no amendment to the provisions of either of the Electric Revenue Bond Resolutions shall be made without the consent of the owner of each Electric Revenue Bond affected thereby.

Energy Northwest may at any time surrender to the Trustee for cancellation by it any Electric Revenue Bonds previously executed and delivered, which Energy Northwest may have acquired in any manner whatsoever, and such Electric Revenue Bonds upon such surrender for cancellation shall be deemed to be paid and no longer outstanding under either of the Electric Revenue Bond Resolutions.

Neither the obligations of Energy Northwest under the Electric Revenue Bond Resolutions and the liens, pledges, charges, trusts, covenants and agreements of Energy Northwest made or provided for in the Electric Revenue Bond Resolutions, nor any Supplemental Resolutions authorizing Parity Reimbursement Obligations and/or Other Parity Obligations, shall be discharged or satisfied with respect to such Parity Reimbursement Obligations or Other Parity Obligations, respectively, until such Parity Reimbursement Obligations shall have been paid in accordance with their terms.

Summary of the Supplemental Electric Revenue Bond Resolutions

Debt Service Account. Each Supplemental Electric Revenue Bond Resolution creates and establishes a special trust account of the Debt Service Fund which shall be held by the Trustee subject to the lien of the related Project's Electric Revenue Bond Resolution. The Debt Service Accounts shall be funded as provided in the related Electric Revenue Bond Resolution and amounts therein shall be used and applied as provided in the related Supplemental Electric Revenue Bond Resolution and in the related Electric Revenue Bond Resolution.

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BOOK-ENTRY SYSTEM

The information in this section concerning DTC, Euroclear Bank SA/NV as operator of the Euroclear System ("Euroclear") and Clearstream Banking, S.A., Luxembourg ("Clearstream Banking") (DTC, Euroclear and Clearstream Banking together, the "Clearing Systems"), and DTC's book-entry-only system has been provided by DTC, Euroclear and Clearstream Banking for use in disclosure documents such as this Official Statement.

DTC will act initially as Securities Depository for the Series 2025-A/B Bonds. Euroclear and Clearstream Banking are participants of DTC and facilitate the clearance and settlement of securities transactions by electronic book-entry transfer between their respective account holders.

The information set forth below is subject to any change in or reinterpretation of the rules, regulations and procedures of the Clearing Systems currently in effect and Energy Northwest and Bonneville expressly disclaim any responsibility to update this Official Statement to reflect any such changes. The information herein concerning the Clearing Systems has been obtained from sources that Energy Northwest believes to be reliable, but neither Energy Northwest, Bonneville nor the Underwriters take any responsibility for the accuracy or completeness of the information set forth herein. Investors wishing to use the facilities of any of the Clearing Systems are advised to confirm the continued applicability of the rules, regulations and procedures of the relevant Clearing System. Energy Northwest, Bonneville and the Underwriters will not have any responsibility or liability for any aspect of the records relating to, or payments made on account of, beneficial ownership interests in the Series 2025-A/B Bonds held through the facilities of any Clearing System or for maintaining, supervising or reviewing any records relating to such beneficial ownership interests.

Energy Northwest and Bonneville cannot and do not give any assurance that (1) DTC will distribute payments of debt service on the Series 2025-A/B Bonds, or redemption or other notices, to participants of the Clearing Systems ("Participants"), (2) Participants or others will distribute debt service payments paid to DTC or its nominee (as the registered owner of the Series 2025-A/B Bonds), or redemption or other notices, to the Beneficial Owners, or that they will do so on a timely basis, or (3) DTC or the other Clearing Systems will serve and act in the manner described in this Official Statement. The current rules applicable to DTC are on file with the Securities and Exchange Commission, and the current procedures of DTC to be followed in dealing with DTC Participants (hereinafter defined) are on file with DTC.

DTC Book-Entry-Only System

Clearing Systems

DTC will act initially as Securities Depository for the Series 2025-A/B Bonds. The Series 2025-A/B Bonds will be issued as fully registered securities in the name of Cede & Co. (DTC's partnership nominee) or such other name as may be requested by an authorized representative of DTC. One fully-registered Series 2025-A Bond certificate will be issued for each maturity of the Series 2025-A Bonds, in the principal amount of such maturity, and will be deposited with DTC. One fully-registered Series 2025-B (Taxable) Bond certificate will be issued for each maturity of the Series 2025-B (Taxable) Bonds, in the principal amount of such maturity, and will be deposited with DTC.

DTC is a limited-purpose trust company organized under the New York Banking Law, a "banking organization" within the meaning of the New York Banking Law, a member of the Federal Reserve System, a "clearing corporation" within the meaning of the New York Uniform Commercial Code, and a "clearing agency" registered pursuant to the provisions of Section 17A of the Securities Exchange Act of 1934, as amended. 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 of DTC, National Securities Clearing Corporation and Fixed Income Clearing Corporation, all of which are registered clearing agencies. DTCC is owned by the users of its regulated subsidiaries. Access to the DTC system is also available to others such as both U.S. and non-U.S. securities brokers and dealers, banks, trust companies, and clearing corporations that clear through or maintain a custodial relationship with a Direct Participant, either directly or indirectly ("Indirect Participants"). The DTC Rules applicable to its Participants are on file with the Securities and Exchange Commission. More information about DTC can be found at www.dtcc.com.

Purchases of the Series 2025-A/B Bonds under the DTC system, in denominations of $5,000 or any integral multiple thereof, must be made by or through Direct Participants, which will receive a credit for the Series 2025-A/B Bonds on DTC's records. The ownership interest of each actual purchaser of each Series 2025-A/B 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 beneficial ownership interests in the Series 2025-A/B 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 beneficial ownership interests in the Series 2025-A/B Bonds, except in the event that use of the book-entry system for the Series 2025-A/B Bonds is discontinued.

To facilitate subsequent transfers, all Series 2025-A/B 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 Series 2025-A/B Bonds with DTC and their registration in the name of Cede & Co., or such other DTC nominee, do not affect any change in beneficial ownership. DTC has no knowledge of the actual Beneficial Owners of the Series 2025-A/B Bonds; DTC's records reflect only the identity of the Direct Participants to whose accounts such Series 2025-A/B Bonds are credited, which may or may not be the Beneficial Owners. The Direct and Indirect Participants will remain responsible for keeping account of their holdings on behalf of their customers.

When notices are given, they shall be sent by the Bond Registrar to DTC only. Conveyance of notices and other communications by DTC to Direct Participants, by Direct Participants to Indirect Participants, and by Direct Participants and Indirect Participants to Beneficial Owners will be governed by arrangements among them, subject to any statutory or regulatory requirements as may be in effect from time to time.

Redemption notices will be sent to DTC. If less than all of the Series 2025-A/B Bonds are to be redeemed, Energy Northwest may select the Series and maturity or maturities, including any sinking fund redemptions of Term Bonds, to be redeemed. If less than all of the Series 2025-A Bonds of any maturity are to be redeemed, the Series 2025-A Bonds or portions thereof to be redeemed are to be selected by the Trustee or DTC, as applicable, by lot. If the Series 2025-B (Taxable) Bonds are registered in book-entry only form and so long as DTC or a successor securities depository is the sole registered owner of such Series 2025-B (Taxable) Bonds, if less than all of the Series 2025-B (Taxable) Bonds of a maturity are called for prior redemption, the particular Series 2025-B (Taxable) Bonds or portions thereof to be redeemed shall be allocated on a pro rata pass-through distribution of principal basis in accordance with DTC procedures, provided that, so long as the Series 2025-B (Taxable) Bonds are held in book-entry form, the selection for redemption of such Series 2025-B (Taxable) Bonds shall be made in accordance with the operational arrangements of DTC then in effect, and, if the DTC operational arrangements do not allow for redemption on a pro rata pass-through distribution of principal basis, the Series 2025-B (Taxable) Bonds will be selected for redemption, in accordance with DTC procedures, by lot.

Neither DTC nor Cede & Co. (nor any other DTC nominee) will consent or vote with respect to the Series 2025-A/B Bonds unless authorized by a Direct Participant in accordance with DTC's MMI Procedures. Under its usual procedures, DTC mails an Omnibus Proxy to Energy Northwest as soon as possible after the record date. The Omnibus Proxy assigns Cede & Co.'s consenting or voting rights to those Direct Participants to whose accounts Series 2025-A/B Bonds are credited on the record date (identified in a listing attached to the Omnibus Proxy).

Redemption proceeds, distributions, and dividend payments on the Series 2025-A/B Bonds will be made to Cede & Co., or such other nominee as may be requested by an authorized representative of DTC. DTC's practice is to credit Direct Participants' accounts upon DTC's receipt of funds and corresponding detail information from Energy Northwest or the Bond Registrar, on payable date in accordance with their respective holdings shown on DTC's records. Payments by 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 Bond Registrar, or Energy Northwest, subject to any statutory or regulatory requirements as may be in effect from time to time. Payment of redemption proceeds, distributions and dividend payments to Cede & Co. (or any other nominee as may be requested by an authorized representative of DTC) is the responsibility of Energy Northwest or the Bond Registrar, disbursement of such payments to Direct Participants will be the responsibility of DTC, and disbursement of such payments to the Beneficial Owners will be the responsibility of Direct and Indirect Participants.

DTC may discontinue providing its services as securities depository with respect to the Series 2025-A/B Bonds at any time by giving reasonable notice to Energy Northwest or the Bond Registrar. Under such circumstances, in the event that a successor securities depository is not obtained, Series 2025-A/B Bond certificates are required to be printed and delivered.

Energy Northwest may decide to discontinue use of the system of book-entry-only transfers through DTC (or a successor securities depository). In that event, Series 2025-A/B Bonds will be printed.

In reading this Official Statement it should be understood that while the Series 2025-A/B Bonds are in the Book-Entry-Only System, references in other sections of this Official Statement to registered owners should be read to include the person for which the Participant acquires an interest in the Series 2025-A/B Bonds, but (i) all rights of ownership must be exercised through DTC and the Book-Entry-Only System, and (ii) except as described above, notices that are to be given to registered owners under the Trust Indenture will be given only to DTC.

Euroclear and Clearstream Banking

Euroclear and Clearstream Banking have advised as follows:

Euroclear and Clearstream Banking each hold securities for their customers and facilitate the clearance and settlement of securities transactions by electronic book-entry transfer between their respective account holders. Euroclear and Clearstream Banking provide various services including safekeeping, administration, clearance and settlement of internationally traded securities and securities lending and borrowing. Euroclear and Clearstream Banking also deal with domestic securities markets in several countries through established depositary and custodial relationships. Euroclear and Clearstream Banking have established an electronic bridge between their two systems across which their respective participants may settle trades with each other.

Euroclear and Clearstream Banking customers are worldwide financial institutions, including underwriters, securities brokers and dealers, banks, trust companies and clearing corporations. Indirect access to Euroclear and Clearstream Banking is available to other institutions that clear through or maintain a custodial relationship with an account holder of either system, either directly or indirectly.

Clearing and Settlement Procedures

Any Series 2025-A/B Bonds sold in offshore transactions will be initially issued to investors through the book-entry facilities of DTC, for the account of its participants, including but not limited to Euroclear and Clearstream Banking. If the investors are participants in Clearstream Banking and Euroclear in Europe, or indirectly through organizations that are participants in the Clearing Systems, Clearstream Banking and Euroclear will hold omnibus positions on behalf of their participants through customers' securities accounts in Clearstream Banking's and Euroclear's names on the books of their respective depositories. In all cases, the record holder of the Series 2025-A/B Bonds will be DTC's nominee and not Euroclear or Clearstream Banking. The depositories, in turn, will hold positions in customers' securities accounts in the depositories' names on the books of DTC. Because of time zone differences, the securities account of a Clearstream Banking or Euroclear participant as a result of a transaction with a participant, other than a depository holding on behalf of Clearstream Banking or Euroclear, will be credited during the securities settlement processing day, which must be a business day for Clearstream Banking or Euroclear, as the case may be, immediately following the DTC settlement date. These credits or any transactions in the securities settled during the processing will be reported to the relevant Euroclear participant or Clearstream Banking participant on that business day. Cash received in Clearstream Banking or Euroclear as a result of sales of securities by or through a Clearstream Banking participant or Euroclear participant to a DTC Participant, other than the depository for Clearstream Banking or Euroclear, will be received with value on the DTC settlement date but will be available in the relevant Clearstream Banking or Euroclear cash account only as of the business day following settlement in DTC.

Transfers between participants will occur in accordance with DTC rules. Transfers between Clearstream Banking participants or Euroclear participants will occur in accordance with their respective rules and operating procedures. Cross-market transfers between persons holding directly or indirectly through DTC, on the one hand, and directly or indirectly through Clearstream Banking participants or Euroclear participants, on the other, will be effected in DTC in accordance with DTC rules on behalf of the relevant European international clearing system by the relevant depositories; however, cross-market transactions will require delivery of instructions to the relevant European international clearing system by the counterparty in the system in accordance with its rules and procedures and within its established deadlines in European time. The relevant European international clearing system will, if the transaction meets its settlement requirements, deliver instructions to its depository to take action to effect final settlement on its behalf by delivering or receiving securities in DTC, and making or receiving payment in accordance with normal procedures for same day funds settlement applicable to DTC. Clearstream Banking participants or Euroclear participants may not deliver instructions directly to the depositories.

Energy Northwest will not impose any fees in respect of holding the Series 2025-A/B Bonds; however, holders of book-entry interests in the Series 2025-A/B Bonds may incur fees normally payable in respect of the maintenance and operation of accounts in the Clearing Systems.

Initial Settlement

Interests in the Series 2025-A/B Bonds will be in uncertified book-entry form. Purchasers electing to hold book-entry interests in the Series 2025-A/B Bonds through Euroclear and Clearstream Banking accounts will follow the settlement procedures applicable thereto and applicable to DTC. Book-entry interests in the Series 2025-A/B Bonds will be credited by DTC to Euroclear and Clearstream Banking participants' securities clearance accounts on the business day following the date of delivery of the Series 2025-A/B Bonds against payment (value as on the date of delivery of the Series 2025-A/B Bonds). DTC participants acting on behalf of purchasers electing to hold book-entry interests in the Series 2025-A/B Bonds through DTC will follow the delivery practices applicable to securities eligible for DTC's Same Day Funds Settlement system. DTC participants' securities accounts will be credited with book-entry interests in the Series 2025-A/B Bonds following confirmation of receipt of payment to Energy Northwest on the date of delivery of the Series 2025-A/B Bonds.

Secondary Market Trading

Secondary market trades in the Series 2025-A/B Bonds will be settled by transfer of title to book-entry interests in the Clearing Systems. Title to such book-entry interests will pass by registration of the transfer within the records of Euroclear, Clearstream Banking or DTC, as the case may be, in accordance with their respective procedures. Book-entry interests in the Series 2025-A/B Bonds may be transferred within Euroclear and within Clearstream Banking and between Euroclear and Clearstream Banking in accordance with procedures established for these purposes by Euroclear and Clearstream Banking. Book-entry interests in the Series 2025-A/B Bonds may be transferred within DTC in accordance with procedures established for this purpose by DTC. Transfer of book-entry interests in the Series 2025-A/B Bonds between Euroclear or Clearstream Banking and DTC shall be effected in accordance with procedures established for this purpose by Euroclear, Clearstream Banking and DTC.

Special Timing Considerations

Investors should be aware that investors will only be able to make and receive deliveries, payments and other communications involving the Series 2025-A/B Bonds through Euroclear or Clearstream Banking on days when those systems are open for business. In addition, because of time-zone differences, there may be complications with completing transactions involving Clearstream Banking and/or Euroclear on the same business day as in the United States. U.S. investors who wish to transfer their interests in the Series 2025-A/B Bonds, or to receive or make a payment or delivery of Bonds, on a particular day, may find that the transactions will not be performed until the next business day in Luxembourg if Clearstream Banking is used, or Brussels if Euroclear is used.

Clearing Information

The Underwriters expect that the Series 2025-A/B Bonds will be accepted for clearance through the facilities of Euroclear and Clearstream Banking. The international securities identification number, common code and CUSIP number for the Series 2025-A/B Bonds are set out on the cover page of this Official Statement.

General

None of Euroclear, Clearstream Banking or DTC is under any obligation to perform or continue to perform the procedures referred to above, and such procedures may be discontinued at any time.

Neither Energy Northwest, the Underwriters nor any of their agents will have any responsibility for the performance by Euroclear, Clearstream Banking or DTC or their respective direct or indirect participants or account holders of their respective obligations under the rules and procedures governing their operations or the arrangements referred to above.

Limitations

For so long as the Series 2025-A/B Bonds are registered in the name of DTC or its nominee, Cede & Co., Energy Northwest and the Bond Registrar will recognize only DTC or its nominee, Cede & Co., as the registered owner of the Series 2025-A/B Bonds for all purposes, including payments, notices and voting. So long as Cede & Co. is the registered owner of the Series 2025-A/B Bonds, references in this Official Statement to registered owners of the Series 2025-A/B Bonds shall mean Cede & Co. and shall not mean the Beneficial Owners of the Series 2025-A/B Bonds.

Because DTC is treated as the owner of the Series 2025-A/B Bonds for substantially all purposes, Beneficial Owners may have a restricted ability to influence in a timely fashion remedial action or the giving or withholding of requested consents or other directions. In addition, because the identity of Beneficial Owners is unknown to Energy Northwest or DTC, it may be difficult to transmit information of potential interest to Beneficial Owners in an effective and timely manner. Beneficial Owners should make appropriate arrangements with their broker or dealer regarding distribution of information regarding the Series 2025-A/B Bonds that may be transmitted by or through DTC.

Energy Northwest will have no responsibility or obligation with respect to:

- the accuracy of the records of DTC, its nominee or any Direct Participant or Indirect Participant with respect to any Beneficial Ownership interest in the Series 2025-A/B Bonds;
- the delivery to any Direct Participant or Indirect Participant or any other person, other than a registered owner as shown in the Bond Register, of any notice with respect to the Series 2025-A/B Bonds including, without limitation, any notice of redemption with respect to the Series 2025-A/B Bonds;
- the payment to any Direct Participant or Indirect Participant or any other person, other than a registered owner as shown in the Bond Register, of any amount with respect to the principal of, premium, if any, or interest on, the Series 2025-A/B Bonds;
- the selection by DTC or any Participant of any person to receive payment in the event of a partial redemption of the Series 2025-A/B Bonds;
- any consent given or action taken by DTC or its nominee as registered owner; or
- any other matter.

Prior to any discontinuation of the book entry only system hereinabove described, Energy Northwest and the Bond Registrar may treat Cede & Co. (or such other nominee of DTC) as, and deem Cede & Co. (or such other nominee) to be, the absolute registered owner of the Series 2025-A/B Bonds for all purposes whatsoever, including, without limitation:

- the payment of principal, premium, if any, and interest on the Series 2025-A/B Bonds;
- giving notices of redemption and other matters with respect to the Series 2025-A/B Bonds;
- registering transfers with respect to the Series 2025-A/B Bonds; and
- the selection of Series 2025-A/B Bonds for redemption.

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SUMMARY OF THE CONTINUING DISCLOSURE AGREEMENTS

To assist the Underwriters in complying with Rule 15c2-12, Energy Northwest and Bonneville entered into written agreements (the "Disclosure Agreements") for the benefit of the holders and beneficial owners of the Series 2025-A/B Bonds to provide continuing disclosure.

Definitions.

In addition to the definitions set forth in the Net Billed Resolutions and the Disclosure Agreements, which apply to any capitalized term used in the Disclosure Agreements, the following capitalized terms shall have the following meanings:

"*BPA Annual Information*" means financial information and operating data generally of the type included in the final Official Statement for the Series 2025-A/B Bonds in the following tables in Appendix A under the headings "POWER SERVICES": "Bonneville Power Services' Ten Largest Customers by Sales" and "Historical Average PF Preference Rates," "TRANSMISSION SERVICES": "Transmission Services' Ten Largest Customers By Sales," "BONNEVILLE FINANCIAL OPERATIONS": "Historical Capital Spending by Program by Fiscal Year," "Historical Capital Funding by Source and Fiscal Year," "Bonneville's Fiscal Year-End Financial Reserves," "Historical Federal System Operating Revenue and Operating Expense Compared to Historical Streamflow," "Federal System Statement of Revenues and Expenses," and "Statement of Non-Federal Debt Service Coverage and United States Treasury Payments."

"*Energy Northwest Annual Information*" means financial information and operating data generally of the type included in the final Official Statement for the Series 2025-A/B Bonds in the table labeled "Energy Northwest Revenue Bonds Outstanding as of March 31, 2025" under the heading "ENERGY NORTHWEST—ENERGY NORTHWEST INDEBTEDNESS" and in the table labeled "Statement of Operations" under the heading "ENERGY NORTHWEST—THE COLUMBIA GENERATING STATION —Annual Costs."

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

"*FCRPS*" means the Federal Columbia River Power System.

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

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

"*Rule 15c2-12*" means Rule 15c2-12 under the Securities Exchange Act of 1934, as amended through the date of this Disclosure Agreement, including any official interpretations thereof promulgated on or prior to the effective date of this Disclosure Agreement.

Financial Information.

Bonneville. Bonneville agrees to provide to the MSRB, no later than 180 days after the end of each FCRPS Fiscal Year, commencing with the FCRPS Fiscal Year ending September 30, 2025:

(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 Energy Northwest when such BPA Annual Information has been provided and when such financial statements have been provided.

Energy Northwest. Energy Northwest agrees to provide to the MSRB, no later than 180 days after the end of each Energy Northwest Fiscal Year, commencing with the Energy Northwest Fiscal Year ending June 30, 2025:

(i) the Energy Northwest Annual Information for the Energy Northwest Fiscal Year;

(ii) annual financial statements of Energy Northwest for the Energy Northwest Fiscal Year, prepared in accordance with generally accepted accounting principles applicable to governmental entities; and

(iii) if the annual financial statements provided in accordance with subparagraph (ii) above are not its audited annual financial statements, Energy Northwest shall provide its audited annual financial statements when and if they become available.

Cross-Reference. In lieu of providing the annual financial information and operating data described above, Bonneville and Energy Northwest may specifically cross-reference other documents available to the public on the internet website of the MSRB, or filed with the SEC.

Notice of Failure to Provide Financial Information. Energy Northwest agrees to provide or cause to be provided, in a timely manner, to the MSRB (i) notice of Bonneville's failure to provide the annual financial information described above on or prior to the applicable date set forth above and (ii) notice of Energy Northwest's failure to provide the annual financial information described above on or prior to the applicable date set forth above.

Events Notices.

Energy Northwest agrees to provide or cause to be provided, in a timely manner (not in excess of ten business days after the occurrence of the event), to the MSRB, notice of the occurrence of any of the following events with respect to the Series 2025-A/B Bonds:

i. Principal and interest payment delinquencies;

ii. Non-payment related defaults, if material;

iii. Unscheduled draws on debt service reserves reflecting financial difficulties;

iv. Unscheduled draws on credit enhancements reflecting financial difficulties;

v. Substitution of credit or liquidity providers, or their failure to perform;

vi. Adverse tax opinions, the issuance by the Internal Revenue Service of proposed or final determinations of taxability, Notice of Proposed Issue (IRS Form 5701 – TEB) or other material notices or determinations with respect to the tax status of the Series 2025-A/B Bonds;

vii. Modifications to rights of Series 2025-A/B Bondholders, if material;

viii. Optional, contingent or unscheduled calls of any Series 2025-A/B Bonds other than scheduled sinking fund redemptions for which notice is given pursuant to Exchange Act Release 34-23856, if material, and tender offers;

ix. Defeasances;

x. Release, substitution or sale of property securing repayment of the Series 2025-A/B Bonds, if material;

xi. Rating changes;

xii. Bankruptcy, insolvency, receivership or similar event of Energy Northwest (a "Bankruptcy Event");

xiii. The consummation of a merger, consolidation, or acquisition involving Energy Northwest or the sale of all or substantially all of the assets of Energy Northwest, other than in the ordinary course of business, the entry into a definitive agreement to undertake such an action or the termination of a definitive agreement relating to any such actions, other than pursuant to its terms, if material;

xiv. Appointment of a successor or additional trustee or the change of name of a trustee, if material;

xv. Incurrence of a financial obligation of Energy Northwest or Bonneville, if material, or agreement to covenants, events of default, remedies, priority rights, or other similar terms of a financial obligation of Energy Northwest or Bonneville, any of which affect security holders, if material; and

xvi. Default, event of acceleration, termination event, modification of terms, or other similar events under the terms of the financial obligation of Energy Northwest or Bonneville, any of which reflect financial difficulties.

A Bankruptcy Event is considered to occur when any of the following occur: the appointment of a receiver, fiscal agent or similar officer for Energy Northwest in a proceeding under the U.S. Bankruptcy Code or in any other proceeding under state or federal law in which a court or governmental authority has assumed jurisdiction over substantially all of the assets or business of Energy Northwest, or if such jurisdiction has been assumed by leaving the existing governing body and officials or officers in possession but subject to the supervision and orders of a court or governmental authority, or the entry of an order confirming a plan of reorganization, arrangement or liquidation by a court or governmental authority having supervision or jurisdiction over substantially all of the assets or business of the obligated person.

The term financial obligation means a (i) debt obligation; (ii) derivative instrument entered into in connection with, or pledged as security or a source of payment for, an existing or planned debt obligation; or (iii) guarantee of (i) or (ii). The term financial obligation shall not include municipal securities as to which a final official statement has been provided to the MSRB consistent with Rule 15c2-12.

Solely for purposes of disclosure, and not intending to modify this undertaking, Energy Northwest advises with (i) reference to items (iii) and (x) above that no debt service reserves or property secure payment of the Series 2025-A/B Bonds, and (ii) reference to items (iv) and (v) above that no credit enhancements or liquidity facilities secure payment of the Series 2025-A/B Bonds.

Availability of Information from the MSRB.

Energy Northwest 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.

Termination, Modification.

The obligations of Bonneville and Energy Northwest to provide annual financial information and the obligation of Energy Northwest to provide timely notices of the above-listed events shall terminate upon the legal defeasance, prior redemption or payment in full of all of the Series 2025-A/B Bonds. This section, or any provision hereof, shall be null and void if Bonneville and Energy Northwest (i) obtain an opinion of nationally recognized bond counsel to the effect that those portions of the Rule that require this Disclosure Agreement, or any such provision, are invalid, have been repealed retroactively or otherwise do not apply to the Series 2025-A/B Bonds; and (ii) notifies the MSRB of such opinion and the cancellation of this Disclosure Agreement.

In the event of any amendment or waiver of a provision of this Disclosure Agreement, Bonneville and Energy Northwest shall describe such amendment in 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 Energy Northwest, as applicable. In addition, if the amendment relates to the accounting principles to be followed in preparing financial statements, (i) notice of such change shall be given in the same manner as for a listed event under "Events Notices," and (ii) the annual report for the year in which the change is made should present a comparison (in narrative form and also, if feasible, in quantitative form) between the financial statements as prepared on the basis of the new accounting principles and those prepared on the basis of the former accounting principles.

Remedies.

The right of any Owner or Beneficial Owner of Series 2025-A/B Bonds to enforce the provisions of this Disclosure Agreement against Energy Northwest shall be limited to a right to obtain specific enforcement of Energy Northwest's obligations hereunder, and any failure by Energy Northwest to comply with the provisions of this Disclosure Agreement shall not be an event of default under the Resolution or the Supplemental Resolution or with respect to the Series 2025-A/B Bonds.

Specific performance is not available as a remedy against Bonneville for any breach or default by Bonneville under this Disclosure Agreement. Owners and Beneficial Owners of Series 2025-A/B Bonds shall have any rights available to them under law with respect to remedies hereunder against Bonneville.

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ENERGY NORTHWEST • PROJECT 1, COLUMBIA GENERATING STATION AND PROJECT 3 ELECTRIC REVENUE AND REFUNDING BONDS, SERIES 2025-A AND COLUMBIA GENERATING STATION ELECTRIC REVENUE BONDS, SERIES 2025-B (TAXABLE)

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