NEW ISSUE – FULL BOOK-ENTRY

RATINGS
Moody's: Aa3/Fitch: AA-

In the opinion of Orrick, Herrington & Sutcliffe LLP, New York, New York, Bond Counsel to the Agency, (a) 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 2024 Series A Bonds is excluded from gross income for federal income tax purposes under Section 103 of the Internal Revenue Code of 1986, (b) interest on the 2024 Series B Bonds is not excluded from gross income for federal income tax purposes under Section 103 of the Internal Revenue Code of 1986, and (c) interest on the 2024 Series A and B Bonds is exempt from individual income taxes imposed by the State of Utah. In the further opinion of Bond Counsel, interest on the 2024 Series A Bonds is not a specific preference item for purposes of the federal individual alternative minimum tax. Bond Counsel observes that interest on the 2024 Series A Bonds included in adjusted financial statement income of certain corporations is not excluded from the federal corporate alternative minimum tax. Bond 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 2024 Series A and B Bonds. See "TAX MATTERS" herein.

IPA
Intermountain Power Agency
Energy for Today & Tomorrow
(a political subdivision of the State of Utah)

$175,000,000
Power Supply Revenue Bonds

$161,215,000 2024 Series A (Tax-Exempt)	$13,785,000 2024 Series B (Federally Taxable)

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

The Power Supply Revenue Bonds, 2024 Series A (Tax-Exempt) (the "2024 Series A Bonds") and 2024 Series B (Federally Taxable) (the "2024 Series B Bonds" and, together with the 2024 Series A Bonds, the "2024 Series A and B Bonds") will be issued as fully registered bonds and, when issued, will be registered in the name of Cede & Co., as nominee of The Depository Trust Company, New York, New York ("DTC"). Purchases of 2024 Series A and B Bonds will be made in book-entry form only, in the principal amount of $5,000 and any integral multiples thereof, through brokers and dealers who are, or who act through, DTC participants. Semiannual interest on the 2024 Series A and B Bonds is payable each January 1 and July 1, commencing January 1, 2025, as more fully described herein. So long as DTC or its nominee is the registered owner of the 2024 Series A and B Bonds, payments of the principal of and interest on such Bonds will be made directly to DTC (see "DESCRIPTION OF THE 2024 SERIES A AND B BONDS – Book-Entry Only System" herein).

The 2024 Series A and B Bonds will be subject to redemption prior to maturity as described herein.

The 2024 Series A and B Bonds are being issued to provide a portion of the funds required to finance the Cost of Acquisition and Construction of a repowering of the Project (such terms, and all other capitalized terms used on this cover page without definition, have the respective meanings assigned thereto in this Official Statement), to fund a deposit to a debt service reserve account, to fund capitalized interest on the 2024 Series A and B Bonds through July 1, 2025 and to pay costs of issuance of the 2024 Series A and B Bonds.

MATURITY SCHEDULE – See Inside Front Cover

The principal or redemption price of, and interest on, the 2024 Series A and B Bonds are payable solely from and secured solely by a pledge and assignment of the Trust Estate (as defined in the Resolution referred to herein) derived by Intermountain Power Agency (the "Agency") from the Project and other funds pledged under the Resolution, including the Revenues (as defined in the Resolution), which include all payments attributable to the Project to be made to the Agency by the Power Purchasers pursuant to the Power Sales Contracts and Renewal Power Sales Contracts referred to herein. Such payments, together with other available Revenues, are to equal the Agency's costs relating to the Project. For a discussion of the source of each Power Purchaser's payments under its Power Sales Contract, see "SECURITY AND SOURCES OF PAYMENT FOR THE 2024 SERIES A AND B BONDS – Power Sales Contracts – *General*" herein; and for a discussion of the source of each Renewal Power Purchaser's payments under its Renewal Power Sales Contract, see "SECURITY AND SOURCES OF PAYMENT FOR THE 2024 SERIES A AND B BONDS – Renewal Power Sales Contracts – *General*" herein. The amounts payable by the Power Purchasers under the Power Sales Contracts and Renewal Power Sales Contracts are payable whether or not the Project or any part thereof has been completed, is operating or operable, or its output is suspended, interrupted, interfered with, reduced or curtailed or terminated in whole or in part.

The 2024 Series A and B Bonds will not be an obligation of the State of Utah or any political subdivision thereof, other than the Agency, nor of any member of the Agency or Power Purchaser and neither the faith and credit nor the taxing power of the State of Utah or any political subdivision thereof or any city or town which is either a member of the Agency or a Power Purchaser or both will be pledged for the payment of the 2024 Series A and B Bonds. The Agency has no taxing power.

The 2024 Series A and B Bonds are offered when, as and if issued and received by the Underwriters, and subject to the approval of legality by Orrick, Herrington & Sutcliffe LLP, New York, New York, Bond Counsel to the Agency, and certain other conditions. Certain legal matters will be passed upon for the Agency by its counsel, Holland & Hart LLP, Salt Lake City, Utah. Certain legal matters will be passed upon for the Underwriters by their counsel, Gilmore & Bell, P.C., Salt Lake City, Utah. Stifel, Nicolaus & Company, Incorporated has acted as Municipal Advisor to the Agency in connection with the 2024 Series A and B Bonds. It is expected that the 2024 Series A and B Bonds in definitive form will be available for delivery to DTC in New York, New York on or about November 15, 2024.

Goldman Sachs & Co. LLC **RBC Capital Markets**

October 25, 2024

MATURITY SCHEDULE
INTERMOUNTAIN POWER AGENCY
$161,215,000
Power Supply Revenue Bonds,
2024 Series A (Tax-Exempt)

Dated: Date of Delivery **Due: as shown below**

Maturity (July 1)	Amount	Interest Rate	Yield	CUSIP Number*
2026	$ 4,875,000	5.000%	2.960%	45884A J20
2027	5,120,000	5.000	2.820	45884A J38
2028	5,375,000	5.000	2.860	45884A J46
2029	5,645,000	5.000	2.900	45884A J53
2030	5,925,000	5.000	2.950	45884A J61
2031	6,220,000	5.000	3.030	45884A J79
2032	6,535,000	5.000	3.100	45884A J87
2033	6,860,000	5.000	3.230	45884A J95
2034	7,205,000	5.000	3.310†	45884A K28
2035	7,565,000	5.000	3.370†	45884A K36
2036	7,940,000	5.000	3.450†	45884A K44
2037	8,340,000	5.000	3.530†	45884A K51
2038	8,755,000	5.000	3.570†	45884A K69
2039	9,195,000	5.000	3.580†	45884A K77
2040	9,655,000	5.000	3.660†	45884A K85
2041	10,135,000	5.000	3.760†	45884A K93
2042	10,640,000	5.000	3.850†	45884A L27
2043	11,175,000	5.000	3.890†	45884A L35
2044	11,735,000	5.000	3.940†	45884A L43
2045	12,320,000	5.000	3.990†	45884A L50

$13,785,000
Power Supply Revenue Bonds,
2024 Series B (Federally Taxable)

Dated: Date of Delivery **Due: as shown below**

$4,530,000 Serial Bonds

Maturity (July 1)	Amount	Interest Rate	Price	CUSIP Number*
2026	$415,000	4.553%	100%	45884A L68
2027	435,000	4.593	100	45884A L76
2028	455,000	4.657	100	45884A L84
2029	475,000	4.707	100	45884A L92
2030	500,000	4.765	100	45884A M26
2031	520,000	4.815	100	45884A M34
2032	550,000	4.910	100	45884A M42
2033	575,000	4.940	100	45884A M59
2034	605,000	4.990	100	45884A M67

$9,255,000 5.435% Term Bonds due July 1, 2045 – Price 100% (CUSIP No. 45884A M75*)

(Without Accrued Interest)

* CUSIP® is a registered trademark of the American Bankers Association. CUSIP data herein is provided by CUSIP Global Services, managed by FactSet Research Systems Inc. on behalf of The American Bankers Association. This information is not intended to create a database and does not serve in any way as a substitute for the CUSIP Services Bureau. CUSIP numbers have been assigned by an independent company not affiliated with the Agency or the Underwriters and are included solely for the convenience of the registered owners of the applicable 2024 Series A and B Bonds. Neither the Agency nor the Underwriters are responsible for the selection or uses of these CUSIP numbers, and no representation is made as to their correctness on the applicable 2024 Series A and B Bonds or as included herein. The CUSIP number for a specific maturity is subject to being changed after the issuance of the 2024 Series A and B Bonds as a result of various subsequent actions including, but not limited to, a refunding in whole or in part or as a result of the procurement of secondary market portfolio insurance or other similar enhancement by investors that is applicable to all or a portion of certain maturities of the 2024 Series A and B Bonds.

† Yield to optional par call on July 1, 2033.

INTERMOUNTAIN POWER AGENCY
10653 South River Front Parkway, Suite 120
South Jordan, Utah 84095

Board of Directors

Nick Tatton – Chair

Joel Eves – Vice Chair
Eric Larsen – Secretary
Allen Johnson – Treasurer
Jason Norlen
Mark Montgomery
Bruce Rigby

Management

Cameron R. Cowan – General Manager
Blaine J. Haacke, Assistant General Manager
Vance K. Huntley – Treasury Manager
Linford E. Jensen – Accounting Manager
Cody R. Combe – Audit Manager

Power Purchasers

Utah

Beaver City*
City of Bountiful*
Bridger Valley Electric Association, Inc.*
Dixie-Escalante Rural Electric Association, Inc.*
City of Enterprise*
Ephraim City*
City of Fairview*
Fillmore City*
Flowell Electric Association, Inc.*
Garkane Energy Cooperative, Inc.*
Heber Light & Power Company*
Holden Town*
City of Hurricane*
Hyrum City*
Kanosh Town*
Kaysville City*
Lehi City*
City of Logan*
Meadow Town
Monroe City
Moon Lake Electric Association, Inc.*
Morgan City*
Mt. Pleasant City*
Mt. Wheeler Power, Inc.*
Murray City*
Town of Oak City*
Parowan City*
Price City*
Spring City*

California

City of Anaheim
City of Burbank*
City of Glendale*
Department of Water and Power of The City of Los Angeles*
City of Pasadena
City of Riverside

* Renewal Power Purchaser

Coordinating Committee

Chairman – Cameron R. Cowan

Power Purchaser(s) Represented	Representative
Murray City	Greg Bellon
City of Logan	Mark Montgomery
All Other Utah Municipal Purchasers	Eric Larsen
Moon Lake Electric Association, Inc.	Yankton Johnson
Mt. Wheeler Power, Inc.	Kevin Robison
All Other Cooperative Purchasers	LaDel Laub

Power Purchaser Represented	Representative
Department of Water and Power of The City of Los Angeles	David Hanson
City of Anaheim	Dukku Lee
City of Burbank	Mandip Samra
City of Glendale	Mark Young
City of Pasadena	Kelly Nguyen (alt.)
City of Riverside	David Garcia

Trustee, Bond Registrar and Paying Agent

The Bank of New York Mellon
Jersey City, New Jersey

Project Manager and Operating Agent

Department of Water and Power of The City of Los Angeles

Counsel to the Agency

Holland & Hart LLP
Salt Lake City, Utah

Bond Counsel to the Agency

Orrick, Herrington & Sutcliffe LLP
New York, New York

Municipal Advisor

Stifel, Nicolaus & Company, Incorporated
Salt Lake City, Utah

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SUMMARY

The following summary does not purport to be complete and is qualified in its entirety by, and should be read in conjunction with, the more detailed information appearing elsewhere in this Official Statement or included by specific reference herein and any supplement or amendment hereto. Capitalized terms used in this Summary and not defined herein have the meanings given to such terms elsewhere in this Official Statement.

Issuer .... Intermountain Power Agency (the "Agency") is a political subdivision of the State of Utah. The Agency has acquired and constructed and is operating the Intermountain Power Project (the "Project"), which consists of, among other things, (i) a two-unit coal-fired steam-electric generating plant with a net rating of 1,800 MW and a switchyard (the "Switchyard"), located near Lynndyl, in Millard County, Utah, (ii) a ±500-kV direct current transmission line approximately 490 miles in length from and including the Intermountain Converter Station (an alternating current/direct current converter station adjacent to the Switchyard) to and including a corresponding converter station at Adelanto, California (collectively, the "Southern Transmission System"), (iii) two 50 mile 345-kV alternating current transmission lines from the Switchyard to the Mona Switchyard in the vicinity of Mona, Utah and a 144 mile 230-kV alternating current transmission line from the Switchyard to the Gonder Switchyard near Ely, Nevada (collectively, the "Northern Transmission System"). The operation and maintenance of the Project are being managed for the Agency by the Department of Water and Power of The City of Los Angeles (the "Department") in its capacity as Operating Agent.

The Agency is undertaking the replacement of the generation facilities of the Project, to consist of the construction and installation of gas-fueled power blocks to replace the coal-fired units, with commercial operation of the gas units anticipated to be achieved during July 2025 (sometimes referred to herein as the "Gas Repowering"), along with (a) the development of capability to increase the percentage of hydrogen to be included in the mix of natural gas and hydrogen fuel to be burned in the gas units beyond the base capability of the gas units, which is 30% hydrogen by volume (the "Hydrogen Betterments") and (b) the entry into contracts with third parties to provide services for (i) natural gas transportation (the "Natural Gas Transportation Contract") and (ii) the conversion of water into hydrogen using renewable energy and the storage of such hydrogen (the "Hydrogen Conversion and Storage Capacity" and together with the Hydrogen Betterments, collectively, the "Hydrogen Facilities"). The Gas Repowering, together with the Natural Gas Transportation Contract and the development of the Hydrogen Facilities, are referred to herein collectively as the "Generation Renewal Project".

Concurrently with the Generation Renewal Project, the Agency also is undertaking the replacement, renewal, and expansion of certain facilities of the Southern Transmission System to provide for an extension of the useful life thereof (as more fully described herein, the "STS Renewal Project"). The cost of acquisition and construction of the STS Renewal Project is expected to be paid from payments-in-aid of construction to be made to the Agency by the Southern California Public Power Authority

("SCPPA") from the proceeds of bonds or other obligations of SCPPA issued or to be issued for such purpose. (See "THE AGENCY'S FINANCING PROGRAM – SCPPA Financing of the Southern Transmission System" in the 2023 Annual Filing referred to herein.) As a result, it is not anticipated that such cost of acquisition and construction of the STS Renewal Project will be paid from the proceeds of the Agency's Bonds (including the 2024 Series A and B Bonds) or other obligations.

The 2024 Series A and B Bonds...................................... The $161,215,000 Power Supply Revenue Bonds, 2024 Series A (Tax-Exempt) (the "2024 Series A Bonds") and $13,785,000 Power Supply Revenue Bonds, 2024 Series B (Federally Taxable) (the "2024 Series B Bonds" and, together with the 2024 Series A Bonds, the "2024 Series A and B Bonds") are being offered in the principal amount per maturity and bearing the interest rates set forth on the inside cover page of this Official Statement.

The 2024 Series A and B Bonds will be issued pursuant to the Agency's Power Supply Revenue Bond Resolution adopted on September 28, 1978, as heretofore supplemented, amended and restated (the "Resolution"), including as supplemented by the Agency's Sixty-Sixth Supplemental Power Supply Revenue Bond Resolution relating to the 2024 Series A and B Bonds adopted on October 2, 2024 (the "Sixty-Sixth Supplemental Resolution"), to finance a portion of the Cost of Acquisition and Construction (as defined in the Resolution) of the Gas Repowering.

On May 12, 2022, the Agency issued $732,755,000 in aggregate principal amount of its Power Supply Revenue Bonds, 2022 Series A (Tax-Exempt) (the "2022 Series A Bonds") and $64,850,000 in aggregate principal amount of its Power Supply Revenue Bonds, 2022 Series B (Federally Taxable) (the "2022 Series B Bonds" and, together with the 2022 Series A Bonds, the "2022 Series A and B Bonds"), pursuant to the Agency's Sixty-First Supplemental Power Supply Revenue Bond Resolution relating to the 2022 Series A and B Bonds adopted on April 28, 2022 (the "Sixty-First Supplemental Resolution"), to finance and refinance a portion of the Cost of Acquisition and Construction of the Gas Repowering.

On August 15, 2023, the Agency issued $767,650,000 in aggregate principal amount of its Power Supply Revenue Bonds, 2023 Series A (Tax-Exempt) (the "2023 Series A Bonds") and $67,395,000 in aggregate principal amount of its Power Supply Revenue Bonds, 2023 Series B (Federally Taxable) (the "2023 Series B Bonds" and, together with the 2023 Series A Bonds, the "2023 Series A and B Bonds"), pursuant to the Agency's Sixty-Second Supplemental Power Supply Revenue Bond Resolution relating to the 2023 Series A and B Bonds adopted on June 5, 2023 (the "Sixty-Second Supplemental Resolution"), to finance a portion of the Cost of Acquisition and Construction of the Gas Repowering. The 2024 Series A and B Bonds, the 2022 Series A and B Bonds, the 2023 Series A and B Bonds and any other Bonds (as defined in the Resolution) which the Agency may issue hereafter will rank equally and be on a parity as to security and source of payment.

Denominations....................... The 2024 Series A and B Bonds are issuable in the denominations of $5,000 or any integral multiple thereof.

Interest Payment Dates......... Interest on the 2024 Series A and B Bonds shall be calculated on the basis of a 360-day year consisting of twelve 30-day months payable on each January 1 and July 1, commencing on January 1, 2025.

Redemption............................ The 2024 Series A and B Bonds are subject to optional and mandatory redemption on the dates and at the redemption prices described herein under the caption "DESCRIPTION OF THE 2024 SERIES A AND B BONDS — Redemption" herein.

Plan of Finance...................... The proceeds of the 2024 Series A and B Bonds will provide a portion of the funds required to finance the Cost of Acquisition and Construction of the Gas Repowering, to fund a deposit to a debt service reserve account, to fund capitalized interest on the 2024 Series A and B Bonds through July 1, 2025 and to pay costs of issuance of the 2024 Series A and B Bonds. See "PLAN OF FINANCING" herein.

Security for the 2024 Series A and B Bonds.......................... The principal or redemption price of, and interest on, the Bonds (including the 2024 Series A and B Bonds) is payable from and secured by the Trust Estate (as defined in "SECURITY AND SOURCES OF PAYMENT FOR THE 2024 SERIES A AND B BONDS – Pledge Effected by the Resolution" herein). For a discussion of the conditions to the issuance by the Agency of additional Bonds, see "SECURITY AND SOURCES OF PAYMENT FOR THE 2024 SERIES A AND B BONDS – Additional Bonds" herein.

The principal of, and interest on, the 2024 Series A and B Bonds also is payable from and secured by the amounts on deposit in the Initial Subaccount in the Debt Service Reserve Account in the Debt Service Fund established pursuant to the Sixty-First Supplemental Resolution as may from time to time be available therefor (including the investments held as a part of such Account). See "SECURITY AND SOURCES OF PAYMENT FOR THE 2024 SERIES A AND B BONDS – Initial Subaccount in Debt Service Reserve Account" herein.

Pursuant to the Sixty-First Supplemental Resolution, the Agency is required to deposit and maintain, or cause to be deposited and maintained, in the Initial Subaccount moneys and Investment Securities in an amount equal to the Initial Subaccount Debt Service Reserve Requirement. The term "Initial Subaccount Debt Service Reserve Requirement" is defined in the Sixty-First Supplemental Resolution to mean, as of any date of calculation, an amount equal to the greatest amount of Aggregate Debt Service (as defined in the Resolution) on all Bonds of each Additionally Secured Series secured by the Initial Subaccount for the then current or any future Fiscal Year. Upon the issuance of the 2024 Series A and B Bonds, the increase in the Initial Subaccount Debt Service Reserve Requirement will be funded from a portion of the proceeds of the 2024 Series A and B Bonds.

See "SECURITY AND SOURCES OF PAYMENT FOR THE 2024 SERIES A AND B BONDS" herein.

Registration of the 2024 Series A and B Bonds...	The 2024 Series A and B Bonds will be issuable as fully registered bonds in the name of Cede & Co., as nominee of The Depository Trust Company ("DTC"). No person acquiring an interest in the 2024 Series A and B Bonds (a "Beneficial Owner") will be entitled to receive a 2024 Series A or B Bond in certificated form, except under the limited circumstances described in this Official Statement in "DESCRIPTION OF THE 2024 SERIES A AND B BONDS – Book-Entry Only System" herein. All references to actions by Holders of the 2024 Series A and B Bonds will refer to actions taken by DTC, upon instructions from DTC Participants, and all references herein to distributions, notices, reports and statements to Holders shall refer to distributions, notices, reports and statements, respectively, to DTC or Cede & Co., as the registered owner of the 2024 Series A and B Bonds, or to DTC Participants for distribution to Beneficial Owners in accordance with DTC procedures. See "DESCRIPTION OF THE 2024 SERIES A AND B BONDS – Book-Entry Only System" herein.
Tax Considerations	In the opinion of Orrick, Herrington & Sutcliffe LLP, New York, New York, Bond Counsel to the Agency, (a) 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 2024 Series A Bonds is excluded from gross income for federal income tax purposes under Section 103 of the Internal Revenue Code of 1986, (b) interest on the 2024 Series B Bonds is not excluded from gross income for federal income tax purposes under Section 103 of the Internal Revenue Code of 1986, and (c) interest on the 2024 Series A and B Bonds is exempt from individual income taxes imposed by the State of Utah. In the further opinion of Bond Counsel, interest on the 2024 Series A Bonds is not a specific preference item for purposes of the federal individual alternative minimum tax. Bond Counsel observes that interest on the 2024 Series A Bonds included in adjusted financial statement income of certain corporations is not excluded from the federal corporate alternative minimum tax. Bond 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 2024 Series A and B Bonds. See "TAX MATTERS" herein.
Trustee	The Bank of New York Mellon, Jersey City, New Jersey.
Agency's Municipal Advisor	Stifel, Nicolaus & Company, Incorporated, Salt Lake City, Utah. See "MUNICIPAL ADVISOR" herein.
Ratings	Moody's Investors Services, Inc. has assigned a rating of "Aa3" and a stable ratings outlook to the 2024 Series A and B Bonds and Fitch Ratings has assigned a rating of "AA-" and a stable ratings outlook to the 2024 Series A and B Bonds. See "RATINGS" herein.

No dealer, broker, salesman or other person has been authorized by Intermountain Power Agency or by the Underwriters to give any information or to make any representations other than as contained or included by specific reference in this Official Statement, and if given or made such other information or representations must not be relied upon as having been authorized by the Agency or the Underwriters. This Official Statement does not constitute an offer to sell or the solicitation of an offer to buy nor shall there be any sale of the 2024 Series A and B Bonds by any person in any jurisdiction in which it is unlawful for such person to make such offer, solicitation or sale.

The information set forth herein, including the information included by specific reference herein, has been furnished by the Agency, the Department of Water and Power of The City of Los Angeles and includes information obtained from other sources which are believed to be reliable. The information and expressions of opinion contained herein are subject to change without notice and neither the delivery of this Official Statement nor any sale made hereunder shall, under any circumstances, create any implication that there has been no change in the affairs of the Agency, the Power Purchasers or any other person or entity discussed herein since the date hereof.

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 part of, their responsibilities to investors under the federal securities laws as applied to the facts and circumstances of this transaction, but the Underwriters do not guarantee the accuracy or completeness of such information.

THE 2024 SERIES A AND B BONDS OFFERED HEREBY HAVE NOT BEEN APPROVED OR DISAPPROVED BY THE SECURITIES AND EXCHANGE COMMISSION NOR HAS THE SECURITIES AND EXCHANGE COMMISSION OR ANY STATE SECURITIES COMMISSION PASSED UPON THE ACCURACY OF THIS OFFICIAL STATEMENT. ANY REPRESENTATION TO THE CONTRARY IS A CRIMINAL OFFENSE.

Except as specifically provided herein, none of the information on the Agency's website is included by reference herein.

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OFFICIAL STATEMENT

RELATING TO

INTERMOUNTAIN POWER AGENCY

(a political subdivision of the State of Utah)

$175,000,000
Power Supply Revenue Bonds

$161,215,000	**$13,785,000**
2024 Series A	**2024 Series B**
(Tax-Exempt)	**(Federally Taxable)**

INTRODUCTORY STATEMENT

General

The purpose of this Official Statement (which includes the cover page and inside cover page hereof, the Appendices hereto and all of the information included herein by specific reference) is to provide information concerning (i) Intermountain Power Agency (the "Agency"), a political subdivision of the State of Utah (the "State"), (ii) the Intermountain Power Project (the "Project"), and (iii) the Agency's $161,215,000 Power Supply Revenue Bonds, 2024 Series A (Tax-Exempt) (the "2024 Series A Bonds") and $13,785,000 Power Supply Revenue Bonds, 2024 Series B (Federally Taxable) (the "2024 Series B Bonds" and, together with the 2024 Series A Bonds, the "2024 Series A and B Bonds").

The Agency is issuing the 2024 Series A and B Bonds under the provisions of the Utah Interlocal Cooperation Act contained in Title 11, Chapter 13, Utah Code Annotated 1953, as amended (the "Act"), and the Agency's Power Supply Revenue Bond Resolution adopted on September 28, 1978, as heretofore supplemented, amended and restated (the "Resolution"), including as supplemented by the Agency's Sixty-Sixth Supplemental Power Supply Revenue Bond Resolution relating to the 2024 Series A and B Bonds adopted on October 2, 2024 (the "Sixty-Sixth Supplemental Resolution").

The 2024 Series A and B Bonds are being offered to provide a portion of the funds required to finance the Cost of Acquisition and Construction (as defined in the Resolution) of the Gas Repowering (as hereinafter defined; see "The Project and the Generation Renewal Project" below), to fund a deposit to a debt service reserve account, to fund capitalized interest on the 2024 Series A and B Bonds through July 1, 2025 and to pay costs of issuance of the 2024 Series A and B Bonds.

On May 12, 2022, the Agency issued $732,755,000 in aggregate principal amount of its Power Supply Revenue Bonds, 2022 Series A (Tax-Exempt) (the "2022 Series A Bonds") and $64,850,000 in aggregate principal amount of its Power Supply Revenue Bonds, 2022 Series B (Federally Taxable) (the "2022 Series B Bonds" and, together with the 2022 Series A Bonds, the "2022 Series A and B Bonds"), all of which remain Outstanding (as defined in the Resolution) as of the date of this Official Statement. The 2022 Series A and B Bonds were authorized pursuant to the Agency's Sixty-First Supplemental Power Supply Revenue Bond Resolution adopted on April 28, 2022 (the "Sixty-First Supplemental Resolution"), which Sixty-First Supplemental Resolution is supplemental to the Resolution, to finance and refinance a portion of the Cost of Acquisition and Construction of the Gas Repowering.

On August 15, 2023, the Agency issued $835,045,000 in aggregate principal amount of its 2023 Series A and B Bonds, all of which remain Outstanding as of the date of this Official Statement. The 2023 Series A and B Bonds were authorized pursuant to the Agency's Sixty-Second Supplemental Power

Supply Revenue Bond Resolution adopted on June 5, 2023 (the "Sixty-Second Supplemental Resolution"), which Sixty-Second Supplemental Resolution is supplemental to the Resolution, to finance a portion of the Cost of Acquisition and Construction of the Gas Repowering.

The 2022 Series A and B Bonds, the 2023 Series A and B Bonds, the 2024 Series A and B Bonds and any other Bonds (as defined in the Resolution) which the Agency may issue hereafter will rank equally and be on a parity as to security and source of payment. See "SECURITY AND SOURCES OF PAYMENT FOR THE 2024 SERIES A AND B BONDS" herein and "SECURITY AND SOURCES OF PAYMENT FOR THE BONDS" in the 2023 Annual Filing referred to under "Inclusion of Information" below. For a discussion of the conditions to the issuance by the Agency of additional Bonds, see "SECURITY AND SOURCES OF PAYMENT FOR THE 2024 SERIES A AND B BONDS – Additional Bonds" herein.

The Bank of New York Mellon, Jersey City, New Jersey (the "Trustee") serves as Trustee under the Resolution for the Bonds, including, without limitation, the 2024 Series A and B Bonds. It has also been appointed as Paying Agent and Bond Registrar for the 2024 Series A and B Bonds pursuant to the Sixty-Sixth Supplemental Resolution.

Capitalized terms used but not otherwise defined herein have the respective meanings set forth in the 2023 Annual Filing.

Security for the 2024 Series A and B Bonds

The principal or redemption price of, and interest on, the Bonds (including the 2024 Series A and B Bonds) is payable from and secured by the Trust Estate (as defined in "SECURITY AND SOURCES OF PAYMENT FOR THE 2024 SERIES A AND B BONDS – Pledge Effected by the Resolution" herein). For a discussion of the conditions to the issuance by the Agency of additional Bonds, see "SECURITY AND SOURCES OF PAYMENT FOR THE 2024 SERIES A AND B BONDS – Additional Bonds" herein.

The principal of, and interest on, the 2024 Series A and B Bonds also is payable from and secured by the amounts on deposit in the Initial Subaccount in the Debt Service Reserve Account in the Debt Service Fund established pursuant to the Resolution as may from time to time be available therefor (including the investments held as a part of such Account). See "SECURITY AND SOURCES OF PAYMENT FOR THE 2024 SERIES A AND B BONDS – Initial Subaccount in Debt Service Reserve Account" herein.

Inclusion of Information

Pursuant to continuing disclosure undertakings adopted by the Agency in connection with the issuance of the 2022 Series A and B Bonds and the 2023 Series A and B Bonds, on March 31, 2023, the Agency filed a document entitled "Annual Disclosure Report for Fiscal Year 2022-2023" (the "2023 Annual Filing") with the Municipal Securities Rulemaking Board (the "MSRB"), through the MSRB's Electronic Municipal Market Access ("EMMA") website, currently located at https://emma.msrb.org. The 2023 Annual Filing contains, among other things, important financial, operating and other information regarding the Agency, the Project and certain of the Power Purchasers (as hereinafter defined), information regarding the security and sources of payment for the Bonds, summaries of certain provisions of the Resolution and certain agreements and other important information that is relevant to the 2024 Series A and B Bonds.

The Agency includes in this Official Statement by this reference the 2023 Annual Filing in its entirety, except that (a) the information in the 2023 Annual Filing is superseded and replaced by the remainder of this Official Statement to the extent the information in the 2023 Annual Filing is inconsistent with the remainder of this Official Statement, (b) the information in APPENDIX A to this Official Statement updates and supplements certain of the information contained in the 2023 Annual Filing, as set forth therein and (c) the Incorporated Information (as defined in the 2023 Annual Filing) with respect to the Department of Water and Power of the City of Los Angeles, California (the "Department"), other than the audited financial statements of the Department for the fiscal years ended June 30, 2023 and 2024 contained therein, is superseded and replaced in its entirety by the information set forth in APPENDIX C hereto.

THIS OFFICIAL STATEMENT MUST BE READ ONLY IN CONJUNCTION WITH THE MATERIALS INCLUDED BY SPECIFIC REFERENCE HEREIN. Copies of the 2023 Annual Filing may be obtained from the MSRB's EMMA website (https://emma.msrb.org). Additionally, the 2023 Annual Filing is available at the following web page: https://www.ipautah.com/financial-information/annual-reports-disclosure/. However, except for the 2023 Annual Filing, none of the other information contained on the Agency's website (www.ipautah.com) is included by reference in this Official Statement.

The Agency

The Agency was organized in June 1977 by 23 Utah municipalities under the Act pursuant to the Intermountain Power Agency Organization Agreement. See "INTERMOUNTAIN POWER AGENCY" in the 2023 Annual Filing.

The Power Purchasers and the Renewal Power Purchasers

The Agency has sold the entire capability of the Project through June 15, 2027 to 35 entities (the "Power Purchasers") on a "take-or-pay" basis (that is, whether or not the Project or any part thereof has been completed, is operating or operable or its output is suspended interrupted, interfered with, reduced or curtailed or terminated in whole or in part, and such payments shall not be subject to reduction whether by offset or otherwise and shall not be conditional upon the performance or nonperformance by any party of any agreement for any cause whatever) pursuant to separate power sales contracts between the Agency and each Power Purchaser which heretofore have been amended, updated and revised in accordance with the terms thereof (said power sales contracts, as so amended, updated and revised, are herein called the "Power Sales Contracts"). The Power Purchasers are 35 utilities consisting of the Department and the California cities of Anaheim, Riverside, Burbank, Glendale and Pasadena (collectively, the "California Purchasers"); the 23 members of the Agency (collectively, the "Utah Municipal Purchasers"); and six rural electric cooperatives serving loads in the States of Utah, Arizona, Colorado, Nevada and Wyoming (collectively, the "Cooperative Purchasers" and, together with the Utah Municipal Purchasers, the "Utah Purchasers"). The California Purchasers, the Utah Municipal Purchasers and the Cooperative Purchasers have contracted, pursuant to their Power Sales Contracts, to purchase 78.943%, 14.040% and 7.017%, respectively, of the net capability of the Generation Station; and the California Renewal Purchasers and the Utah Municipal Renewal Purchasers (as such terms are hereinafter defined) and the Cooperative Purchasers have contracted, pursuant to their Renewal Power Sales Contracts (hereinafter defined), to purchase 78.943%, 13.975% and 7.082%, respectively, of the net capability of the Generation Station. For information regarding the Department (the Department being the only power purchaser having responsibility for in excess of 10% of the costs of the Project under both its Power Sales Contract and its Renewal Power Sales Contract), see APPENDIX C hereto. In addition, the audited financial statements of the Department for the fiscal years ended June 30, 2024 and 2023 may be obtained from the EMMA website of the MSRB, currently located at https://emma.msrb.org.

The Agency previously had included disclosure in its official statements for the public offering of its Bonds and Subordinated Indebtedness regarding the City of Anaheim, California ("Anaheim") but, since Anaheim is not a Renewal Power Purchaser (hereinafter defined), Anaheim's obligation to make payments with respect to the Project will end on June 15, 2027. (Due to the Agency's expectation that interest will be capitalized on this and subsequent Bond offerings, if any, prior to the 2026-2027 fiscal year, the Agency does not anticipate billing Power Purchasers, including Anaheim, for Debt Service with respect to the Bonds prior to the 2025-2026 fiscal year.) For information regarding the respective rights, duties and obligations of the Power Purchasers under the Power Sales Contracts and of the Renewal Power Purchasers under the Renewal Power Sales Contracts, see "SECURITY AND SOURCES OF PAYMENT FOR THE BONDS – Power Sales Contracts" and "– Renewal Power Sales Contracts", respectively, in the 2023 Annual Filing.

The Agency has sold the entire capability of the Project for the period beginning on June 16, 2027 (the "Transition Date") and ending on June 15, 2077 to 30 entities (the "Renewal Power Purchasers") on a "take-or-pay" basis pursuant to separate renewal power sales contracts between the Agency and each Renewal Power Purchaser, as the appendices to such renewal power sales contracts heretofore have been updated in accordance with the terms thereof (said renewal power sales contracts, as so updated, are herein called the "Renewal Power Sales Contracts"). The Renewal Power Purchasers are 30 utilities consisting of the Department and the California cities of Burbank and Glendale (collectively, the "California Renewal Purchasers"); the 21 entities that will remain as members of the Agency from and after June 16, 2027 (collectively, the "Utah Municipal Renewal Purchasers"); and the six Cooperative Purchasers (together with the Utah Municipal Renewal Purchasers, collectively, the "Utah Renewal Purchasers"). The California Renewal Purchasers, the Utah Municipal Renewal Purchasers and the Cooperative Purchasers have contracted, pursuant to their Renewal Power Sales Contracts, to purchase 78.943%, 13.975% and 7.082%, respectively, of the net capability of the Generation Station. For information regarding the respective rights, duties and obligations of the Renewal Power Purchasers under the Renewal Power Sales Contracts, see "SECURITY AND SOURCES OF PAYMENT FOR THE BONDS – Renewal Power Sales Contracts" in the 2023 Annual Filing.

Pursuant to the Excess Power Sales Agreement referred to in "SECURITY AND SOURCES OF PAYMENT FOR THE BONDS – Excess Power Sales Agreement" in the 2023 Annual Filing (as amended, the "Excess Power Sales Agreement"), through June 15, 2027, the Utah Purchasers have sold to the Department and the California cities of Pasadena, Burbank and Glendale (collectively, the "Excess Power Purchasers") their entitlements to the use of the capability of the Project except for any portion of any such entitlement that a Utah Purchaser has, from time to time, recalled under the Excess Power Sales Agreement. So long as no such recall is in effect, the California Purchasers are committed to take or pay for 100% of the capability of the Generation Station, *provided, however*, the Utah Purchasers remain, and will remain, primarily obligated to the Agency under their respective Power Sales Contracts to pay for the Project capability they have sold to the Excess Power Purchasers, but are discharged from such obligation to the extent the Excess Power Purchasers make payments to the Agency on their behalves pursuant to the Excess Power Sales Agreement. However, to the extent set forth in the table below entitled "Percentages of Capability of Generation Station to be Purchased," certain of the Utah Purchasers have recalled portions of their entitlements to the use of the capability of the Project. While such recall, or any recall that the Utah Purchasers may elect to make hereafter, is in effect, the percentage of the capability of the Generation Station that the Excess Power Purchasers will be committed to take or pay for shall be reduced by the percentage of capability of the Generation Station that has been recalled, and each recalling Utah Purchaser will be the only Power Purchaser committed to take or pay for the percentage of capability so recalled by such Power Purchaser. The Utah Purchasers may, subject to the lead times and other requirements of the Excess Power Sales Agreement, recall from the Excess Power Purchasers all or any portion of their aggregate 21.057% entitlements to the use of the capability of the Project.

Recalls under the Excess Power Sales Agreement are made with respect to a "Summer Season" or a "Winter Season" (each a "Season"). The Excess Power Sales Agreement defines a "Summer Season" as each period beginning on March 25 and ending on the following September 24 and a "Winter Season" as each period beginning on September 25 and ending on the following March 24.

Based on the current schedules of power to be sold under the Excess Power Sales Agreement, which schedules are revised annually: (i) the recalling Utah Purchasers have committed, subject to certain permitted adjustments, to sell to the Excess Power Purchasers, until March 24, 2025, their Project capability in excess of that which they have recalled; (ii) certain of the Utah Purchasers have recalled Project capability for various Seasons between March 25, 2025 and June 15, 2027, and may recall all or any portion of their remaining Project capability for such Seasons; and (iii) the remaining Utah Purchasers have committed, subject to certain permitted adjustments, to sell to the Excess Power Purchasers, for the Winter Season beginning on September 25, 2026, their entire Project capability, but may recall, subject to their compliance with the recall requirements of the Excess Power Sales Agreement, all or any portion of their Project capability for such Season.

For a description of the obligations of the respective Power Purchasers to take or pay for capability of the Project, and the rights of the Utah Purchasers to recall capability of the Project, see "SECURITY AND SOURCES OF PAYMENT FOR THE BONDS – Power Sales Contracts" and "– Excess Power Sales Agreement" in the 2023 Annual Filing and "SUMMARY OF CERTAIN PROVISIONS OF THE POWER SALES CONTRACTS" and "SUMMARY OF CERTAIN PROVISIONS OF THE EXCESS POWER SALES AGREEMENT" in Appendix B to the 2023 Annual Filing.

The following table sets forth, as percentages, the capability of the Generation Station that each California Purchaser and the Utah Municipal Purchasers and the Cooperative Purchasers that have recalled such capability are obligated to purchase and pay for from and after March 25, 2024. The table is based on: (i) the percentage each California Purchaser purchases under its Power Sales Contract and, as to the Excess Power Purchasers, the capability of the Generation Station each is presently committed to purchase under the Excess Power Sales Agreement; and (ii) the percentage of capability of the Generation Station that has been recalled by certain of the Utah Municipal Purchasers and the Cooperative Purchasers as described above. Any other recalls that may be effected hereafter will correspondingly decrease the percentages shown below for the Excess Power Purchasers. See "POWER PURCHASERS' COST AND ENTITLEMENT SHARES" and "SUMMARY OF CERTAIN PROVISIONS OF THE EXCESS POWER SALES AGREEMENT – Excess Entitlement Shares" in Appendix B to the 2023 Annual Filing.

Percentages of Capability of
Generation Station to be Purchased

Power Purchaser	Winter Season beginning 25 Sep 2024	Winter Season beginning 25 Sep 2025	All Other Winter Seasons	Summer Season beginning 25 Mar 2025	All Other Summer Seasons
The Department	63.343%	62.126%	65.971%	60.419%	65.795%
Anaheim	13.225	13.225	13.225	13.225	13.225
Riverside	7.617	7.617	7.617	7.617	7.617
Pasadena	5.699	5.592	5.929	5.443	5.913
Burbank	4.016	3.963	4.131	3.888	4.124
Glendale	2.111	2.077	2.183	2.030	2.178
Utah Municipal Purchasers	3.046	4.456	0.000	6.434	0.204
Cooperative Purchasers	0.944	0.944	0.944	0.944	0.944

Pursuant to the Agreement for Sale of Renewal Excess Power referred to in "SECURITY AND SOURCES OF PAYMENT FOR THE BONDS – Agreement for Sale of Renewal Excess Power" in the 2023 Annual Filing, for 50 years from and after the Transition Date, the Utah Renewal Purchasers have sold to the Department their entitlements to the use of the capability of the Project except for any portion of any such entitlement that a Utah Renewal Purchaser may, from time to time, recall under the Agreement for Sale of Renewal Excess Power. See "RENEWAL POWER PURCHASERS' COST AND ENTITLEMENT SHARES" and "SUMMARY OF CERTAIN PROVISIONS OF THE AGREEMENT FOR SALE OF RENEWAL EXCESS POWER – Excess Entitlement Shares" in Appendix B to the 2023 Annual Filing.

The Project and the Generation Renewal Project

The Agency has acquired and constructed and is operating the Project, which consists of (i) a two-unit coal-fired steam-electric generating plant with a net rating of 1,800 MW (the "Intermountain Generating Station") and a switchyard (the "Switchyard"), located near Lynndyl, in Millard County, Utah, (ii) a ±500-kV direct current transmission line approximately 490 miles in length from and including the Intermountain Converter Station (an alternating current/direct current converter station adjacent to the Switchyard) to and including a corresponding converter station at Adelanto, California (collectively, the "Southern Transmission System"), (iii) two 50-mile 345-kV alternating current transmission lines from the Switchyard to the Mona Switchyard in the vicinity of Mona, Utah and a 144-mile 230-kV alternating current transmission line from the Switchyard to the Gonder Switchyard near Ely, Nevada (collectively, the "Northern Transmission System"), (iv) a microwave communications system, (v) a railcar service center located in Springville, in Utah County, Utah (the "Railcar Service Center") and (vi) certain water rights and coal supplies (which water rights and coal supplies, together with the Intermountain Generating Station, the Switchyard and the Railcar Service Center, are referred to herein collectively as the "Generation Station"). The operation and maintenance of the Project are managed for the Agency by the Department in its capacity as Operating Agent.

All of the facilities of the Project have been in commercial operation since May 1, 1987. See "PROJECT OPERATIONS – Management and Operation of the Project" in the 2023 Annual Filing for a description of the operating history of the Project.

The Project facilities have, generally, operated with a high degree of availability, exceeding the national average of coal-fired generating units of comparable size. In recent years, primarily due to market conditions, system demand, relatively low natural gas prices and the GHG Cost Factor (as defined in the 2023 Annual Filing), the Project has been noncompetitive relative to other resources available to the California Purchasers and, as a result of such factors and the unavailability of fuel, the Project has operated at less than industry-average capacity levels. Neither the Agency nor the Operating Agent is aware of any operational or equipment problems that would materially and adversely affect future operations of the coal units through the commercial operation date of the natural gas units scheduled to occur during July 2025. See "PROJECT OPERATIONS – Management and Operation of the Project" and "– Fuel Supply" in the 2023 Annual Filing.

Further to the Agency's strategic planning initiatives (i) in 2015, the Agency and the Power Purchasers amended the Power Sales Contracts to provide, among other things, for the repowering of the Project to consist of gas-fueled power blocks to replace the coal-fired units, with commercial operation of the gas units to be achieved by July 1, 2025 (such amendments to the Power Sales Contracts are hereinafter referred to as the "Power Sales Contracts Amendments," and such repowering of the Project is referred to in the Power Sales Contracts Amendments as the "Gas Repowering"); and (ii) the Coordinating Committee established pursuant to the Power Sales Contracts (the "Coordinating Committee") (see "COORDINATING COMMITTEE" in the 2023 Annual Filing) and the Agency's Board of Directors have approved (a) the development of capability to increase the percentage of hydrogen to be included in the mix of natural gas and hydrogen fuel to be burned in the gas units beyond the base capability of the gas units, which is 30% hydrogen by volume (the "Hydrogen Betterments"), along with (b) the entry into contracts with third parties to provide services for (i) natural gas transportation through 2045 (the "Natural Gas Transportation Contract"), and (ii) the conversion of water into hydrogen using renewable energy and the storage of such hydrogen, with the facilities necessary to provide such services (the "Hydrogen Conversion and Storage Capacity" and together with the Hydrogen Betterments, collectively, the "Hydrogen Facilities") to be substantially complete by October 1, 2025. The Gas Repowering, including the Natural Gas Transportation Contract, together with the development of the Hydrogen Facilities, including the Hydrogen Conversion and Storage Capacity, are referred to herein collectively as the "Generation Renewal Project"). Concurrently with the Generation Renewal Project, the Agency also is undertaking the replacement, renewal, and expansion of certain facilities of the

Southern Transmission System to provide for an extension of the useful life thereof (as more fully described herein, the "STS Renewal Project").

Following the effectiveness of the Renewal Power Sales Contracts, the Department, in its capacity as a Power Purchaser, requested, and the Project's governing bodies approved, a reduction in the design capacity and changes in the configuration of the natural gas facilities contemplated by the Power Sales Contracts Amendments (known under such contracts as an "Alternative Repowering"). Upon the effectiveness of the Alternative Repowering, the Power Sales Contracts were revised as necessary to describe the Alternative Repowering. Such revisions provide for the construction of two combined-cycle natural gas-fired power blocks, each power block consisting of one gas turbine, a heat recovery steam generator train and a single steam turbine, with an approximate combined net generation capability of 840 MW, where "net generation capability" means gross power generation less auxiliary load for generation and transmission support. See "ELECTRIC INDUSTRY RESTRUCTURING – California Electric Energy Actions," "ENVIRONMENTAL AND HEALTH FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY – Regulation of Greenhouse Gases," "SECURITY AND SOURCES OF PAYMENT FOR THE BONDS – Generation Renewal Project" and "INTERMOUNTAIN POWER AGENCY – The Interlocal Cooperation Act" in the 2023 Annual Filing.

Hydrogen Facilities

The costs of the Hydrogen Facilities (consisting of the Hydrogen Betterments and the Hydrogen Conversion and Storage Capacity) are being funded by the Power Purchasers to the extent such elect to facilitate the development of such facilities. The costs of the Hydrogen Betterments are and some of the initial costs of the Hydrogen Conversion and Storage Capacity have been funded by payments to a "Hydrogen Betterments Fund" established by and funded pursuant to resolutions adopted by the Coordinating Committee, the Renewal Contract Coordinating Committee established pursuant to the Renewal Power Sales Contracts (the "Renewal Contract Coordinating Committee") (see "RENEWAL CONTRACT COORDINATING COMMITTEE" in the 2023 Annual Filing) and the Agency. The balance of the costs of the Hydrogen Conversion and Storage Capacity are being funded pursuant to the Hydrogen Billing Procedure described below. The Department and the Cities of Burbank and Glendale are the only Power Purchasers that have elected to make payments to the Hydrogen Betterments Fund. The Agency bills those Power Purchasers for such payments on a monthly basis. The Hydrogen Betterments Fund is not a fund or account established pursuant to the Resolution and, therefore, is not a part of the Trust Estate, nor is it pledged as security for the payment of the Bonds (including the 2024 Series A and B Bonds).

In addition, on March 3, 2022, the Coordinating Committee, the Renewal Contract Coordinating Committee and the Agency approved a Hydrogen Billing Procedure that provides for the Department and any other Power Purchaser that elects to become a Hydrogen Purchaser (as defined in the Hydrogen Billing Procedure) to pay all of the costs associated with the hydrogen capabilities of the Project (including fixed costs for the Hydrogen Conversion and Storage Capacity and the variable costs of the hydrogen conversion and storage services). The costs for the Hydrogen Conversion and Storage Capacity and the variable costs for the use of such are estimated to be approximately $3,300,000,000 during the term of the contracts providing for such capacity and services, which is expected to be approximately 30 years. The costs addressed under the Hydrogen Billing Procedure represent costs that are not included in Monthly Power Costs (as defined in the Power Sales Contracts). The Hydrogen Billing Procedure provides for a reserve of $60,000,000 to be funded at a rate of $2,500,000 per month beginning in the Agency's fiscal year that commenced on July 1, 2022 (of which $60,000,000 has been funded as of June 30, 2024). The Hydrogen Billing Procedure provides that the Hydrogen Purchasers will procure their hydrogen fuel from the Agency and that the Agency may condition such procurement on the execution of a fuel procurement contract between the Agency and each Hydrogen Purchaser which fuel procurement contracts would require approval of the Hydrogen Purchasers' respective governing bodies. The reserve established by the Hydrogen Billing Procedure is not a fund or account established pursuant to the

Resolution and, therefore, is not a part of the Trust Estate, nor is it pledged as security for the payment of the Bonds (including the 2024 Series A and B Bonds).

STS Renewal Project

The Coordinating Committee and the Agency also have approved a capital improvement plan for the Southern Transmission System consisting of the replacement, renewal, and expansion of AC switchyards, reactive power equipment and associated facilities at the Adelanto Converter Station and the Intermountain Converter Station (collectively, the "STS Renewal Project"), the Cost of Acquisition and Construction for which is expected to be funded through payments-in-aid of construction to be made by the Southern California Public Power Authority ("SCPPA") to the Agency from the proceeds of bonds or other obligations of SCPPA issued and to be issued for such purpose, for the benefit of the California Purchasers. See "THE AGENCY'S FINANCING PROGRAM – SCPPA Financing of the Southern Transmission System" in the 2023 Annual Filing. As a result, it is not anticipated that such Cost of Acquisition and Construction of the STS Renewal Project will be paid from the proceeds of the Agency's Bonds (including the 2024 Series A and B Bonds) or other obligations. The Agency will, however, be responsible for funding a portion of the shared costs incurred with respect to both the Gas Repowering and the STS Renewal Project. The STS Renewal Project is approximately 22% complete and has incurred expenditures of approximately $588,000,000 as of August 31, 2024.

Availability of Information; Continuing Disclosure Undertaking

In order to satisfy the requirements of paragraph (b)(5) of Rule 15c2-12 ("Rule 15c2-12") promulgated by the United States Securities and Exchange Commission (the "SEC"), the Agency's Board of Directors adopted a resolution concurrently with the authorization of the issuance of the 2023 Series A and B Bonds entitled "Master Resolution (2023) as to the Provision of Certain Continuing Disclosure Information With Respect to Certain Designated Series of IPA Bonds" (the "Continuing Disclosure Resolution"), a copy of which is attached as Appendix D to the 2023 Annual Filing.

By resolution adopted on October 2, 2024, the Agency's Board of Directors elected to cause the 2024 Series A and B Bonds to constitute "Covered Bonds" for purposes of the Continuing Disclosure Resolution. As "Covered Bonds," the provisions of the Continuing Disclosure Resolution are applicable to the 2024 Series A and B Bonds.

Under the Continuing Disclosure Resolution, the Agency has covenanted for the benefit of the Holders and the "Beneficial Owners" (as defined in the Continuing Disclosure Resolution) of the Covered Bonds (as defined in the Continuing Disclosure Resolution), which will, upon their issuance, include the 2024 Series A and B Bonds, to provide a report (each, an "Annual Filing") containing certain financial information and operating data relating to the Agency and the Department by not later than nine months after the end of each of the Agency's fiscal years (presently, by each March 31), and to provide notices of the occurrence of certain enumerated events (each, an "Event Notice") with respect to the Covered Bonds (including the 2024 Series A and B Bonds). Each Annual Filing and each Event Notice will be filed by or on behalf of the Agency with the MSRB. Until otherwise designated by the MSRB or the SEC, filings with the MSRB are to be made through the MSRB's EMMA website, currently located at https://emma.msrb.org. The information to be contained in each Annual Filing and each Event Notice is set forth in the Continuing Disclosure Resolution. See Appendix D to the 2023 Annual Filing.

The failure by the Agency to observe or perform any of its obligations under the Continuing Disclosure Resolution will not constitute an Event of Default under the Resolution. If the Agency fails to comply with any provision of the Continuing Disclosure Resolution, any Holder or "Beneficial Owner" of the Outstanding Covered Bonds (including the 2024 Series A and B Bonds) will be entitled to take such actions as may be necessary and appropriate, including seeking mandamus or specific performance by court order, to cause the Agency to comply with its obligations under the Continuing Disclosure

Resolution. However, the Continuing Disclosure Resolution provides that no Holder or Beneficial Owner of the Covered Bonds (including the 2024 Series A and B Bonds) will have the right to challenge the content or the adequacy of the information contained in any Annual Filing or any Event Notice by judicial proceedings unless the Holders or Beneficial Owners of Covered Bonds representing at least 25% in aggregate principal amount of all Covered Bonds join in such proceedings.

"Beneficial Owner" is defined in the Continuing Disclosure Resolution to mean any person holding a beneficial ownership interest in the Covered Bonds through nominees or depositories (including any person holding such interest through the book-entry system of The Depository Trust Company, New York, New York ("DTC")), together with any other person who is intended to be a beneficiary under Rule 15c2-12 of the Continuing Disclosure Resolution. If any person holding such a beneficial interest seeks to cause the Agency to comply with its obligations under the Continuing Disclosure Resolution, it will be the responsibility of such person to demonstrate that it is a "Beneficial Owner" within the meaning of the Continuing Disclosure Resolution. As described under the caption "DESCRIPTION OF THE 2024 SERIES A AND B BONDS – Book-Entry Only System – *General*" herein, all of the 2024 Series A and B Bonds will be issued only in book-entry form through DTC. See the discussion under the same caption for a description of DTC's current procedures with respect to the enforcement of bondholders' rights.

Except as described in the following paragraph, during the past five years, the Agency has complied in all material respects with all of its obligations under each undertaking it has made pursuant to the provisions of paragraph (b)(5) of Rule 15c2-12.

The Agency engaged a third-party to file the 2023 Annual Filing with the MSRB's EMMA website, which filing was timely made. However, the Agency recently discovered that such third-party neglected to associate that filing with the CUSIP numbers for two maturities of the 2022 Series B Bonds. That third-party subsequently made a filing with EMMA that associated the 2023 Annual Filing with those two CUSIPs, and the Agency has established procedures to ensure that all future Annual Filings (as defined in the Agency's continuing disclosure undertakings) are associated with all of the Agency's outstanding Bonds that are the subject of a continuing disclosure undertaking by the Agency.

Other

This Official Statement (including the information included by specific reference herein) includes summaries of the terms of the 2024 Series A and B Bonds, the Resolution, certain provisions of the Act and other statutes, regulations, orders and opinions and certain contracts and other arrangements for the supply of power and energy and the raising of revenues for the payment of the 2024 Series A and B Bonds and the other indebtedness of the Agency. The summaries of and references to all documents, statutes, regulations, orders, opinions, reports and other instruments referred to or included by specific reference herein do not purport to be complete, comprehensive or definitive, and each such summary and reference is qualified in its entirety by reference to each such document, statute, regulation, order, opinion, report or instrument.

In connection with the preparation of this Official Statement, the Agency has relied upon certain information relating to the Department furnished to the Agency by such Power Purchaser and upon certain information obtained from other sources. The information contained or included by specific reference herein is subject to change without notice and the delivery of this Official Statement shall not, under any circumstances, create any implication that there has been no change in the affairs of the Agency, the Power Purchasers or any other person or entity discussed herein or in any information included by specific reference herein since the date hereof.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

The information contained in this Official Statement or included by specific reference herein contains "forward-looking statements" within the meaning of the federal securities laws. These forward-looking statements include, among others, statements concerning expectations, beliefs, opinions, future plans and strategies, anticipated events or trends and similar expressions concerning matters that are not historical facts. Examples of forward-looking statements include, among others, statements concerning purchases of energy by the Power Purchasers, sharing of costs by the Power Purchasers, potential effects of deregulation, potential effects of litigation, current and proposed environmental regulations and related estimated expenditures, access to sources of capital and anticipated uses of capital, the Agency's liquidity and financial condition, financing activities, estimated sales and purchases of power and energy, and estimated construction and other expenditures.

Forward-looking statements are included, among other places, in the sections of this Official Statement captioned "INTRODUCTORY STATEMENT," "ESTIMATED SOURCES AND USES OF FUNDS," and "SECURITY AND SOURCES OF PAYMENT FOR THE 2024 SERIES A AND B BONDS" herein, in APPENDICES A, C and D hereto, and in the sections of the 2023 Annual Filing captioned "INTRODUCTION," "RISK FACTORS," "ELECTRIC INDUSTRY RESTRUCTURING," "ENVIRONMENTAL AND HEALTH FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY," "SECURITY AND SOURCES OF PAYMENT FOR THE BONDS," "INTERMOUNTAIN POWER AGENCY," "THE AGENCY'S FINANCING PROGRAM," "FISCAL YEAR 2023-2024 ANNUAL BUDGET" and "LITIGATION."

The forward-looking statements contained in this Official Statement or included by reference herein are subject to risks and uncertainties that could cause actual results to differ materially from those expressed in or implied by the statements. Accordingly, there can be no assurance that such indicated results will be realized. See "CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION" in the 2023 Annual Filing for a discussion of certain of these risks.

In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur. Prospective purchasers of the 2024 Series A and B Bonds should not place undue reliance on these forward-looking statements, which reflect management's views only as of the date hereof. The Agency does not undertake any obligation to correct or update any forward-looking statements whether as a result of changes in internal estimates or expectations, new information, subsequent events or circumstances or otherwise.

RISK FACTORS

For a discussion of certain risks that could affect payments to be made with respect to the 2024 Series A and B Bonds, see "RISK FACTORS" in the 2023 Annual Filing. Such discussion is not exhaustive, should be read in conjunction with all other parts of this Official Statement and should not be considered a complete description of all risks that could affect payments with respect to the 2024 Series A and B Bonds. Prospective purchasers of the 2024 Series A and B Bonds should analyze carefully the information contained in this Official Statement, including the 2023 Annual Filing included by specific reference herein, as updated by APPENDIX A hereto, as well as the other Appendices hereto.

PLAN OF FINANCING

Purpose of Issue

The Agency is issuing the 2024 Series A and B Bonds in order to (i) finance a portion of the Cost of Acquisition and Construction of the Gas Repowering, (ii) provide moneys sufficient to pay capitalized interest on the 2024 Series A and B Bonds through July 1, 2025, (iii) provide moneys for deposit to the Initial Subaccount in the Debt Service Reserve Account in the Debt Service Fund established under the Resolution, and (iv) pay the costs of issuance of the 2024 Series A and B Bonds.

On May 12, 2022, the Agency issued the 2022 Series A and B Bonds pursuant to the Sixty-First Supplemental Resolution, to finance and refinance a portion of the Cost of Acquisition and Construction of the Gas Repowering. On August 15, 2023, the Agency issued $767,650,000 in aggregate principal amount of its Power Supply Revenue Bonds, 2023 Series A (Tax-Exempt) (the "2023 Series A Bonds") and $67,395,000 in aggregate principal amount of its Power Supply Revenue Bonds, 2023 Series B (Federally Taxable) (the "2023 Series B Bonds" and, together with the 2023 Series A Bonds, the "2023 Series A and B Bonds"), pursuant to the Agency's Sixty-Second Supplemental Power Supply Revenue Bond Resolution relating to the 2023 Series A and B Bonds adopted on June 5, 2023 (the "Sixty-Second Supplemental Resolution"), to finance a portion of the Cost of Acquisition and Construction of the Gas Repowering. The 2022 Series A and B Bonds, the 2023 Series A and B Bonds, the 2024 Series A and B Bonds and any other Bonds (as defined in the Resolution) which the Agency may issue hereafter will rank equally and be on a parity as to security and source of payment.

The Agency expects that the 2024 Series A and B Bonds will provide sufficient funds to pay, in full, the entire remaining Cost of Acquisition and Construction of the Gas Repowering with the exception of the cost to dismantle the IPP coal units and related facilities that will not be used in the operation of the IPP natural gas units. The Agency is not seeking funds for such activities at this time due to the prohibition on intentionally preventing the functionality of the IPP coal units under Utah law. See "ELECTRIC INDUSTRY RESTRUCTURING – Utah Electric Energy Actions – *H.B. 425*" in the 2023 Annual Filing.

Estimated Cost and Schedule of Generation Renewal Project

Gas Repowering. The Cost of Acquisition and Construction of the Gas Repowering, including the portion of such costs shared between the Generation Renewal Project and the STS Renewal Project, were, as of August 31, 2024, projected to total approximately $1,700,000,000. The balance of such estimated costs has been funded in part through proceeds of the 2022 Series A and B Bonds and the 2023 Series A and B Bonds, and is anticipated to be further funded in part through proceeds of the 2024 Series A and B Bonds.

The Agency has contracted with The Industrial Company, a Kiewit company ("TIC") to engineer, procure and construct the Gas Repowering. The contractor is experienced in the design and construction of power generating facilities of the type contemplated by the Gas Repowering. The date-certain, firm price engineering, procurement and construction contract ("EPC Contract") was signed by the Agency and TIC on March 18, 2022. The EPC Contract covers the complete scope of the Gas Repowering, with the exception of the procurement of the Mitsubishi M501JAC combustion turbines which have been procured pursuant to a contract with the manufacturer.

The schedule and performance guarantees under the EPC Contract include liquidated damages for performance, liquidated damages for delay, retentions, a letter of credit and a parent guarantee for 100% of the contract price. The EPC Contract includes output, heat rate, reliability and turbine performance guarantees.

The following describes significant construction milestones for the Gas Repowering and the STS Renewal Project:

Approximate Construction Schedule

Milestone Activity	Date – Scheduled (S) or Actual (A)
Gas Transportation Contract Award	November 2019 (A)
Gas Turbine-Generator Contract Award	February 2020 (A)
Site Preparation Commencement	October 2021 (A)
Generation EPC Contract Award	March 2022 (A)
Intermountain Switchyard Contract Award	June 2021 (A)
Synchronous Condensers Contract Award	November 2022 (A)
Converter Station Contract Award	March 2023 (A)
Natural Gas Available	April 2024 (A)
Gas Repowering Commercial Operation Date	July 2025 (S)
STS Renewal Project Substantially Complete	April 2027 (S)

The Power Sales Contracts provide that the Gas Repowering is to be in commercial operation by July 1, 2025. As of the date of this Official Statement, the engineering, procurement, and construction of the Gas Repowering are approximately 78.91% complete overall, with construction at approximately 78.4% complete. All major construction contracts have been awarded and construction has commenced. The Agency currently anticipates that the natural gas units are to be in commercial operation during July 2025.

The combustion turbines are advanced class units that offer fast ramp and low heat rate and will have the capability of producing energy with a mix of natural gas and green hydrogen upon commencement of commercial operation (30% hydrogen by volume). The Agency anticipates a substantial reduction in greenhouse gas emissions when the new combustion turbines achieve commercial operation and become the sole source of generation for the Project. The reduced nameplate capacity of the units will allow the Southern Transmission System to integrate additional renewable energy for the California Purchasers.

Although substantial completion of the STS Renewal Project is expected to occur after the commercial operation date of the Generation Renewal Project, the Agency expects that the elements of the STS Renewal Project that are necessary for the operation of the Project, as modified by the Generation Renewal Project, will be in place by the commercial operation date of the Generation Renewal Project.

Hydrogen Facilities. The contracts for the Hydrogen Conversion and Storage Capacity provide the Agency with the rights to hydrogen conversion and storage services during the term of such contracts (which is expected to be approximately 30 years). The contracts provide that the related facilities are to be substantially complete by October 1, 2025, providing the capacity to convert water into hydrogen using renewable energy and to store such hydrogen during the testing phase of the Gas Repowering in anticipation of the commercial operation date of the Generation Renewal Project. The hydrogen will be stored in two 4.5-million-barrel caverns to be created in a salt dome formation near the Generation Station site (providing geographically favorable storage). The costs the Agency expects to incur under the contracts for the Hydrogen Conversion and Storage Capacity are estimated to be approximately $3,300,000,000 during the term of such contracts.

The Hydrogen Betterments include upgrades to the natural gas units to facilitate the increase of such units' base capability to use a fuel mix with green hydrogen in excess of 30%, with a goal of reaching 100% of green hydrogen fueled operation by 2045. The cost of the Hydrogen Betterments incurred as of August 31, 2024 is approximately $67,000,000, and are approximately 70% complete. Such Hydrogen Betterments are intended to minimize the improvements required to increase such capability, thereby reducing the cost to increase such capability, if and when the determination is made to increase the hydrogen component of fuel used at the Project. The increase in such capability will not be undertaken prior to June 16, 2027.

ESTIMATED SOURCES AND USES OF FUNDS

The sources and uses of funds in connection with the issuance of the 2024 Series A and B Bonds are estimated to be as follows:

Sources:	2024 Series A	2024 Series B	2024 Series A and B
Principal Amount	$161,215,000.00	$13,785,000.00	$175,000,000.00
Plus: Original Issue Premium	15,425,689.90	–	15,425,689.90
Total Sources	$176,640,689.90	$13,785,000.00	$190,425,689.90
Uses:			
Construction Fund Deposit	$157,191,037.20	$12,110,839.85	$169,301,877.05
Deposit to Debt Service Account in Debt Service Fund for payment of Capitalized Interest on the 2024 Series A and B Bonds (1)	5,060,359.72	451,933.37	5,512,293.09
Deposit to Initial Subaccount in Debt Service Reserve Account in Debt Service Fund (2)	12,970,870.43	1,109,099.33	14,079,969.76
Agency's Costs of Issuance (including Underwriters' Discount) (3)	1,418,422.55	113,127.45	1,531,550.00
Total Uses	$176,640,689.90	$13,785,000.00	$190,425,689.90

(1) Such amount will pay all interest payable on the 2024 Series A and B Bonds through July 1, 2025.

(2) Upon such deposit, amount on deposit in Initial Subaccount will be equal to the Debt Service Reserve Requirement therefor.

(3) Includes legal, advisory, bond rating and printing fees and other costs of issuance.

SECURITY AND SOURCES OF PAYMENT FOR THE 2024 SERIES A AND B BONDS

Pledge Effected by the Resolution

The Resolution provides that the Bonds, including, without limitation, the 2024 Series A and B Bonds, shall be direct and special obligations of the Agency payable solely from and secured solely by the Trust Estate, which is defined to mean (i) the proceeds of the sale of the Bonds, (ii) the Revenues, and (iii) all Funds and Accounts established by the Resolution (other than (X) the Debt Service Reserve Account in the Debt Service Fund, (Y) any Decommissioning Fund which may be established pursuant to the Resolution and (Z) the STS Capital Improvement Construction Fund), including the investments and investment income, if any, thereof, subject only to the provisions of the Resolution permitting the application thereof for the purposes and on the terms and conditions set forth therein. (The Hydrogen Betterments Fund and the reserve established by the Hydrogen Billing Procedure referred to herein (see "INTRODUCTORY STATEMENT – Hydrogen Facilities" herein) were not established by the Resolution, so they are not pledged to the payment of the Bonds.)

The Agency heretofore has established three separate Decommissioning Funds under the Resolution, as more fully described in "Decommissioning Funds" below.

"Revenues" is defined in the Resolution to mean (a) all revenues, income, rents and receipts derived or to be derived by the Agency from or attributable to the ownership and operation of the Project, including all revenues attributable to the Project or to the payment of the costs thereof received or to be received by the Agency under the Power Sales Contracts and the Renewal Power Sales Contracts or under any other contract for the sale of power, energy, transmission or other service from the Project or any part thereof or any contractual arrangement with respect to the use of the Project or any portion thereof or the services, output or capacity thereof, (b) the proceeds of any insurance, including the proceeds of any self-insurance fund, covering business interruption loss relating to the Project, and (c) interest received or to be received on any moneys or securities (other than in the Construction Fund or the STS Capital Improvement Construction Fund) held pursuant to the Resolution and required to be credited to the Revenue Fund. Interest earned on any moneys or investments in any Decommissioning Fund established pursuant to the Resolution shall be held in such Fund for the purposes thereof, and is not required to be transferred to the Revenue Fund. In addition, since the Hydrogen Betterments Fund was not established by the Resolution, interest earned on any moneys or investments therein also are not required to be credited to the Revenue Fund.

Principal of and interest on the 2024 Series A and B Bonds will rank on a parity with each other, with principal of and interest on the 2022 Series A and B Bonds, with principal of and interest on the 2023 Series A and B Bonds and with principal of and interest on each other Series of Bonds which the Agency may issue hereafter. See “SECURITY AND SOURCES OF PAYMENT FOR THE 2024 SERIES A AND B BONDS – Additional Bonds” herein.

The Bonds will not be obligations of the State of Utah or any political subdivision thereof, other than the Agency, or any member of the Agency, any Power Purchaser, any Renewal Power Purchaser or the Project Manager or Operating Agent and neither the faith and credit nor the taxing power of the State of Utah or any political subdivision thereof or any city or town which is either a member of the Agency or a Power Purchaser or a Renewal Power Purchaser or both will be pledged for the payment of Bonds. No holder of Bonds or receiver or trustee in connection with the payment of Bonds will have the right to compel the State of Utah, any political subdivision thereof or any city or town which is either a member of the Agency or a Power Purchaser or a Renewal Power Purchaser or both to exercise its appropriation or taxing powers. The Agency has no taxing power.

For a further discussion of the security and sources of payment for the 2024 Series A and B Bonds, see “SUMMARY OF CERTAIN PROVISIONS OF THE RESOLUTION – Pledge Effected by the Resolution” and “– Nature of Obligation” in Appendix A to the 2023 Annual Filing.

Flow of Funds

The Resolution establishes the following Funds for the application of Revenues while Bonds are Outstanding:

Fund	**Held By**
Revenue Fund	Agency
Debt Service Fund	Trustee
Debt Service Account	
Debt Service Reserve Account	
Subordinated Indebtedness Fund	Trustee
Subordinated Indebtedness Debt Service Account	
Such other accounts as may be established by the Agency in such Fund	
Self-Insurance Fund	Agency

Pursuant to the Resolution, all Revenues received are to be deposited promptly in the Revenue Fund. Each month, amounts in the Revenue Fund are to be used to pay Operating Expenses for such month. After such payment (or provision for payment) of Operating Expenses, monthly payments in the amounts indicated below are to be made from the Revenue Fund to the following Funds and Accounts in the following order of priority:

1. To the Debt Service Account and to each separate subaccount in the Debt Service Reserve Account in the Debt Service Fund, the respective amounts required so that the balances in such Account and subaccounts (excluding, in the case of the Debt Service Account, the amount set aside from the proceeds of Bonds or other evidences of indebtedness of the Agency for payment of interest on Bonds in excess of the amount thereof to be applied to pay interest accrued and unpaid and to accrue on Bonds to the last day of the then current calendar month) equal the Accrued Aggregate Debt Service and the Debt Service Reserve Requirement related thereto, respectively. The Trustee will apply amounts in the Debt Service Account to the payment of principal or sinking fund redemption price of and interest on Bonds when due.

2. To the Subordinated Indebtedness Debt Service Account in the Subordinated Indebtedness Fund and each other account within the Subordinated Indebtedness Fund, such amounts as shall be required to be deposited thereto so that the balance therein or the amount deposited thereto, as the case may be, shall equal the amount required to be on deposit therein as of the end of such month or the amount required to be deposited thereto during such month, as applicable, determined as provided in the respective resolutions, indentures or other instruments, including any Supplemental Resolution, relating to such account or the Subordinated Indebtedness (as defined in the Resolution) payable therefrom or secured thereby. The Trustee will apply amounts in the Subordinated Indebtedness Debt Service Account and such other accounts to the purposes specified with respect thereto in the respective resolutions, indentures or other instruments, including any Supplemental Resolution, applicable thereto.

3. To the Self-Insurance Fund, one-twelfth of the total amount provided for such purpose in the then current Annual Budget, *provided, however,* that if a deficiency in said Fund is to be restored over a period which extends beyond the fiscal year during which such restoration shall have commenced pursuant to the provisions of the Resolution, then the deposits in each month to said Fund during such subsequent fiscal year shall be in the amount determined pursuant to the Resolution.

Funds paid by SCPPA to the Agency for deposit into the STS Capital Improvement Construction Fund and funds paid by the Power Purchasers to the Agency for deposit into any Decommissioning Fund will be deposited directly into those funds. Funds held in any Decommissioning Fund will not be part of the Trust Estate. For a more detailed discussion of the application of monies deposited in the various funds and accounts, see "SUMMARY OF CERTAIN PROVISIONS OF THE RESOLUTION – Application of Revenues" in Appendix A to the 2023 Annual Filing.

Initial Subaccount in Debt Service Reserve Account

Pursuant to the Sixty-First Supplemental Resolution, the Agency has established a subaccount in the Debt Service Reserve Account in the Debt Service Fund known as the "Initial Subaccount," which Subaccount is for the benefit and security of all Holders of the Bonds of each Additionally Secured Series secured thereby. The term "Additionally Secured Series" is defined in the Sixty-First Supplemental Resolution to mean (a) the 2022 Series A and B Bonds and (b) any Series of Bonds (including, without limitation, the 2023 Series A and B Bonds and the 2024 Series A and B Bonds) issued after the date of adoption of the Sixty-First Supplemental Resolution for which the Supplemental Resolution authorizing the Bonds of such Series shall provide that the payment of the principal or sinking fund Redemption Price, if any, of, and interest on, the Bonds of such Series shall be secured, in addition to the pledge and assignment created pursuant to the Resolution in favor of all of the Bonds, by a pledge and assignment of amounts on deposit in the Initial Subaccount; *provided, however*, that no Variable Interest Rate Bonds shall be additionally secured by amounts on deposit in the Initial Subaccount; and *provided, further,* that if any Series of Bonds is to be an Additionally Secured Series, then it will be a condition to the issuance of the Bonds of such Series that the amount on deposit in the Initial Subaccount after giving effect to the issuance of the Bonds of such Series is equal to the Initial Subaccount Debt Service Reserve Requirement (hereinafter defined).

Pursuant to the Sixty-First Supplemental Resolution, the amounts on deposit in the Initial Subaccount as may from time to time be available therefor (including the investments held as a part of such Subaccount) are pledged and assigned to the Holders of the Bonds of each Additionally Secured Series secured thereby, including the 2024 Series A and B Bonds, subject only to the provisions of the Resolution permitting the application thereof for the purposes and on the terms and conditions set forth in the Resolution.

Amounts in the Initial Subaccount are to be applied to make payment of the principal or sinking fund redemption price of, or interest on, the Bonds of each Additionally Secured Series secured thereby (including the 2024 Series A and B Bonds) when due in the event that amounts on deposit in the Debt Service Account in the Debt Service Fund are not sufficient therefor, ratably, based on the deficiency that exists with respect to each Additionally Secured Series secured thereby.

Pursuant to the Sixty-First Supplemental Resolution, the Agency is required to deposit and maintain, or cause to be deposited and maintained, in the Initial Subaccount moneys and Investment Securities in an amount equal to the Initial Subaccount Debt Service Reserve Requirement. The term "Initial Subaccount Debt Service Reserve Requirement" is defined in the Sixty-First Supplemental Resolution to mean, as of any date of calculation, an amount equal to the greatest amount of Aggregate Debt Service (as defined in the Resolution) on all Bonds of each Additionally Secured Series secured by the Initial Subaccount for the then current or any future Fiscal Year. (See "SUMMARY OF CERTAIN PROVISIONS OF THE RESOLUTION – Definitions" in Appendix A to the 2023 Annual Filing for the definition of Aggregate Debt Service.) Upon the issuance of the 2024 Series A and B Bonds, the increase in the Initial Subaccount Debt Service Reserve Requirement will be funded from a portion of the proceeds of the 2024 Series A and B Bonds.

Whenever the amount on deposit in the Initial Subaccount exceeds the Initial Subaccount Debt Service Reserve Requirement, such excess will be deposited in the Revenue Fund established pursuant to the Resolution and applied to the purposes to which other amounts in the Revenue Fund are required to be applied (see "SUMMARY OF CERTAIN PROVISIONS OF THE RESOLUTION – Application of Revenues" in Appendix A to the 2023 Annual Filing); *provided*, *however*, that unless otherwise approved by the Agency and by the Coordinating Committee, such excess must be applied to the purchase, redemption or provision for payment of Bonds or Subordinated Indebtedness.

In the event of the refunding or defeasance of any Bonds of an Additionally Secured Series secured by the Initial Subaccount, the Trustee will, upon the direction of an authorized officer of the Agency, withdraw from the Initial Subaccount all or any portion of the amounts accumulated therein and transfer the amount so withdrawn to itself, as such Trustee, to be held for the payment of the principal or redemption price, if applicable, and interest on such Bonds being refunded or defeased; *provided*, *however*, that such withdrawal will not be made unless (i) immediately thereafter, the Bonds being refunded or defeased shall be deemed to have been paid within the meaning of the Resolution and (ii) the amount remaining in the Initial Subaccount, after giving effect to the issuance of any Bonds being issued to refund any Bonds being refunded and the disposition of the proceeds thereof, shall not be less than the Initial Subaccount Debt Service Reserve Requirement.

Construction Fund

The Resolution establishes a Construction Fund, to be held by the Agency, into which will be paid amounts required by the provisions of the Resolution and any Supplemental Resolution and, at the option of the Agency, any moneys received for or in connection with the Project by the Agency, unless required to be otherwise applied as provided in the Resolution. In addition, proceeds of insurance for physical loss or damage to the Project, including proceeds of any self-insurance fund, or of contractors' performance bonds pertaining to the period of construction of the Project will be paid into the Construction Fund. Within the Construction Fund, a separate account will be established for any Capital Improvements, the Cost of Acquisition and Construction of which is to be paid out of the Construction Fund.

The Agency will pay from the Construction Fund the Cost of Acquisition and Construction of each Capital Improvement, the Cost of Acquisition and Construction of which is to be paid out of the Construction Fund.

The completion of construction of any Capital Improvements shall be evidenced by a certificate or certificates of an Authorized Officer, filed with the records of the Agency, stating (i) that such Capital Improvements have been completed in accordance with the plans and specifications applicable thereto and in accordance with the Construction Management and Operating Agreement, (ii) the date of such completion, and (iii) the amount, if any, required in the opinion of the signer or signers for the payment of any remaining part of the Cost of Acquisition and Construction thereof. Upon the filing of such certificate, the balance in the separate account in the Construction Fund established therefor in excess of the amount, if any, stated in such certificate shall be transferred to the Trustee for deposit to each separate subaccount in the Debt Service Reserve Account in the Debt Service Fund, such amount as shall be necessary to make the amount of such subaccount equal to the Debt Service Reserve Requirement related thereto (or, if the amount to be so transferred shall not be sufficient to make the deposits required to be made pursuant to this clause with respect to all of the separate subaccounts in the Debt Service Reserve Account, then such amount to be so transferred shall be applied ratably, in proportion to the amount necessary for deposit into each such subaccount), and any balance shall be transferred to the Revenue Fund for application to the retirement of Bonds by purchase or redemption or for application to the reduction of the cost of Project power and energy to the Power Purchasers under the Power Sales Contracts and to the Renewal Power Purchasers under the Renewal Power Sales Contracts. If subsequent to the filing of such certificate it shall be determined that any amounts specified in such certificate as being required for the payment of any remaining part of the Cost of Acquisition and Construction are no longer so required, such fact shall be evidenced by a certificate or certificates of an Authorized Officer filed with the records of the Agency stating such fact and any amount shown therein as no longer being required shall be transferred to the Trustee for deposit to each separate subaccount in the Debt Service Reserve Account in the Debt Service Fund, such amount as shall be necessary to make the amount of such subaccount equal to the Debt Service Reserve Requirement related thereto (or, if the amount to be so transferred shall not be sufficient to make the deposits required to be made pursuant to this clause with respect to all of the separate subaccounts in the Debt Service Reserve Account, then such amount to be so transferred shall be applied ratably, in proportion to the amount necessary for deposit into each such subaccount), and any balance shall be transferred to the Revenue Fund for application to the retirement of Bonds by purchase or redemption or for application to the reduction of the cost of Project power and energy to the Power Purchasers under the Power Sales Contracts and to the Renewal Power Purchasers under the Renewal Power Sales Contracts.

STS Capital Improvement Construction Fund

The Resolution establishes an STS Capital Improvement Construction Fund, to be held by the Agency, into which will be paid all payments-in-aid of construction received by the Agency from SCPPA in respect of the STS Renewal Project and certain other Capital Improvements to the Southern Transmission System that SCPPA determines shall be financed by SCPPA. (See "THE AGENCY'S FINANCING PROGRAM – SCPPA Financing of the Southern Transmission System" in the 2023 Annual Filing.) Amounts in the STS Capital Improvement Construction Fund shall be applied to the Cost of Acquisition and Construction of the STS Renewal Project or such other Southern Transmission System Capital Improvements.

The STS Capital Improvement Construction Fund shall not be a part of the Trust Estate and, therefore, is not pledged to the payment of the Bonds.

Decommissioning Funds

At such time as the Agency shall determine, there may be established by Supplemental Resolution one or more Decommissioning Funds to provide for costs of decommissioning, retirement or disposal of facilities of the Project. Each Decommissioning Fund shall be held by the Agency. The amounts to be credited to any such Fund, and the purposes to which amounts in any such Fund are to be applied, shall be set forth in the Supplemental Resolution establishing such Fund.

The Agency heretofore has established three separate Decommissioning Funds under the Resolution, as follows: (1) one such fund designated as the "Coal-Fired Generating Unit Decommissioning Fund", to provide for payment of the costs of decommissioning, retirement or disposal of the Retired Generation and Related Facilities and Properties (as defined in the Power Sales Contracts); (2) one such fund designated as the "STS Renewal Decommissioning Fund", to provide for payment of the Actual STS Decommissioning Cost (as defined in the Supplemental Resolution establishing such Fund); and (3) one such fund designated as the "Project Component Decommissioning Fund", consisting of four separate accounts, designated respectively as the Gas Unit 1 Retirement Account, the Gas Unit 2 Retirement Account, the Northern Transmission System Retirement Account and the Southern Transmission System Retirement Account, each of which accounts shall be used for the accumulation of funds to pay Retirement Costs (as defined in the Renewal Power Sales Contracts) with respect to each of the respective Project Components, as indicated by the name of the account.

Each Decommissioning Fund shall not be a part of the Trust Estate and, therefore, is not pledged to the payment of the Bonds.

Agency Rate Covenant

The Agency has represented in the Resolution that it has, and will have as long as any Bonds are Outstanding, good right and lawful power to establish and collect rates and charges with respect to the Project, subject only to the terms of the Power Sales Contracts, the Renewal Power Sales Contracts, the Construction Management and Operating Agreement and other related contracts. Pursuant to the Resolution, the Agency has covenanted at all times to establish and collect rates and charges with respect to the Project to provide Revenues at least sufficient, together with other available funds, for the payment in each fiscal year of the sum of: (i) Operating Expenses, (ii) Aggregate Debt Service with respect to Bonds, (iii) the amount, if any, required to be paid into each separate subaccount in the Debt Service Reserve Account in the Debt Service Fund established under the Resolution, (iv) the amount to be paid into each separate account in the Subordinated Indebtedness Fund, and all other amounts payable in respect of, Subordinated Indebtedness, (v) the amount, if any, to be paid into the Self-Insurance Fund established under the Resolution and (vi) all other charges or liens payable out of Revenues.

Additional Bonds

The Agency reserves the right under the Resolution to issue additional Bonds for purposes of the Project and on the terms and conditions specified in the Resolution, which will rank equally and be on a parity, as to security and source of payment, with all other Bonds (including the 2024 Series A and B Bonds). See "SUMMARY OF CERTAIN PROVISIONS OF THE RESOLUTION – Additional Bonds Other than Refunding Bonds" in Appendix A to the 2023 Annual Filing.

Power Sales Contracts

General. Under the Power Sales Contracts, the Power Purchasers are entitled to Project (as defined in the Power Sales Contracts) generation and transmission capabilities based on their respective Generation Entitlement Shares (as defined in the Power Sales Contracts) and transmission entitlements and are obligated to make payments therefor.

Each Power Sales Contract between the Agency and a Power Purchaser constitutes an obligation of the parties until the terms of all of the Power Sales Contracts expire on June 15, 2027. As long as any Bonds or Subordinated Indebtedness is outstanding or until provision has been made for the payment of all outstanding Bonds and Subordinated Indebtedness, the Power Sales Contracts may not be terminated or amended in any manner which will reduce the amount of, or extend the time for, the payments that are pledged as security for Bonds and Subordinated Indebtedness or which will impair or adversely affect the rights of the holders of Bonds or Subordinated Indebtedness. The Agency caused all such Bonds and Subordinated Indebtedness to have been legally defeased such that, based on the Agency's interpretation of the effect of Transition Project Indebtedness (as defined below) on such expiration, no indebtedness of the Agency will preclude the expiration of the Power Sales Contracts on June 15, 2027. "Transition Project Indebtedness" is defined in the Power Sales Contracts to mean Bonds (as defined in the Power Sales Contracts) or other obligations issued by the Agency prior to June 16, 2027 that by their terms shall be scheduled to remain outstanding after June 16, 2027.

The Agency does not interpret the foregoing restrictions on termination and amendment of the Power Sales Contracts to cause the Power Sales Contracts to be extended beyond the stated termination date in the Power Sales Contracts, notwithstanding the existence of Bonds or Subordinated Indebtedness constituting Transition Project Indebtedness on such date. The Agency amended the Resolution to express that intention.

Payments are to be made by the Power Purchasers on a "take-or-pay" basis. The payment obligations under the Power Sales Contracts constitute operating expenses of the respective California Purchasers and Utah Municipal Purchasers payable solely from their electric revenue funds, and general obligations of the respective Cooperative Purchasers.

Each Power Purchaser that is a municipally-owned electric system has covenanted in its Power Sales Contract to establish, maintain and collect rates and charges for the electric service it furnishes sufficient to provide revenues which, together with its available electric system reserves, are adequate to enable it to pay to the Agency all amounts payable under its Power Sales Contract and to pay all other amounts payable from, and all liens on and lawful charges against, its electric system revenues. See "SUMMARY OF CERTAIN PROVISIONS OF THE POWER SALES CONTRACTS – Nature of Obligation" in Appendix B to the 2023 Annual Filing.

The Power Sales Contracts provide that the obligations of the respective Power Purchasers are several and not joint except for failure to pay money pursuant to a provision of a Power Sales Contract. A failure by a Power Purchaser to make payments when due under its Power Sales Contract may result in larger payments being made by the other Power Purchasers in subsequent periods for the purpose of enabling the Agency to pay operating expenses, debt service and other costs of the Project and to maintain required reserves therefor. To the extent the amount to be paid by the non-paying Power Purchaser is not offset by revenues from sales of power or transmission service derived by the Agency in respect of such non-paying Power Purchaser's Generation Entitlement Share or transmission entitlement, such non-payment may result in deficits in funds and accounts established under the Resolution. In such event, the Agency would be required to amend, in accordance with the Power Sales Contracts and the Resolution, the Annual Budget (as defined in the Power Sales Contracts) to provide increases in subsequent billings to all Power Purchasers, including the non-paying Power Purchaser, equal to the amount of such deficiency. Such increased billings are not conditioned upon any transfer of the non-paying Power

Purchaser's Generation Entitlement Share or transmission entitlement to the other Power Purchasers. Amounts thereafter collected from such non-paying Power Purchaser are to be credited against the next billings of such other Power Purchasers as appropriate.

In the event of a default or inability to perform by a Power Purchaser under its Power Sales Contract, the Agency may proceed to enforce the Power Purchaser's covenants or obligations thereunder, or seek damages for the breach thereof, by action at law or in equity. The Power Sales Contracts also provide that if a payment due under the Power Sales Contracts remains unpaid when due, the Agency may, upon 120 days' written notice to the Power Purchaser, discontinue the delivery of capacity and energy to, and the use of Project facilities by, such Power Purchaser while the default continues. Except as a result of a transfer of the defaulting Power Purchaser's rights to delivery of capacity and energy and the use of Project facilities, the discontinuance by the Agency of delivery of capacity and energy to and the use of the Project facilities by a defaulting Power Purchaser will not reduce the obligation of such Power Purchaser to make payments under its Power Sales Contract. For information regarding certain acts adopted by the California Legislature in recent years that may limit the Agency's ability to sell or otherwise transfer a defaulting Power Purchaser's Generation Entitlement Share or electric energy attributable thereto to California investor-owned or publicly-owned electric utilities to recover lost revenues resulting from such default, see "ENVIRONMENTAL AND HEALTH FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY – Regulation of Greenhouse Gases – *Federal and California Greenhouse Gas Initiatives*" in the 2023 Annual Filing.

See "SUMMARY OF CERTAIN PROVISIONS OF THE POWER SALES CONTRACTS" in Appendix B to the 2023 Annual Filing.

Monthly Power Costs. During each Power Supply Year (as defined in the Power Sales Contracts), each Power Purchaser is obligated to pay its share of Monthly Power Costs, which consist, generally, of all of the Agency's costs resulting from the ownership, operation and maintenance of, and renewals and replacements to, the Project, to the extent not paid from the proceeds of Bonds and Subordinated Indebtedness or from notes or other evidences of indebtedness issued in anticipation thereof. Such costs, which consist of a minimum cost component and a variable cost component, are billed monthly. Power Supply Years coincide with the Agency's fiscal years, which end at 12:01 a.m. on July 1.

The minimum cost component is billed each month for the then current month based on the estimates contained in the Annual Budget prepared by the Agency prior to the beginning of each Power Supply Year, as such Annual Budget may be amended during such year. For each month, the minimum cost component includes:

(i) the amounts which the Resolution requires the Agency to pay or deposit during such month into funds or accounts for debt service on, and reserve requirements for, Bonds and Subordinated Indebtedness;

(ii) one-twelfth of the amount which the Agency is required under the Resolution to pay or deposit during the Power Supply Year which includes such month into any other fund or account established by the Resolution, including any amount needed to eliminate a deficiency in any fund established under the Resolution whether or not resulting from a default in payments by any Power Purchaser of amounts due under any Power Sales Contract;

(iii) one-twelfth of the costs of producing and delivering capacity and energy from the Project during the Power Supply Year which includes such month, including ordinary operation and maintenance costs, costs of water, overhead and certain fixed costs of fuel for the Project; and

(iv) one-twelfth of the amount necessary during the Power Supply Year which includes such month to pay or provide reserves for payment of amounts required to be paid pursuant to the Act to counties, municipalities and school districts affected by the Project, Payments in Lieu of Ad Valorem Taxes (as defined in the Power Sales Contracts) and all other taxes which the Agency is required to pay.

The variable cost component is billed each month for the immediately preceding month. The variable cost component of Monthly Power Costs consists of all costs of fuel not included in the minimum cost component and is to be billed based on the cost of fuel utilized during such month.

If there is any revision of the Annual Budget after the commencement of any Power Supply Year, the amounts determined pursuant to clauses (ii), (iii) and (iv) above are to be appropriately adjusted to evenly apportion any increase or decrease over the remaining months of such Power Supply Year. For a further discussion of the Agency's budgeting process, see "Budgeting" below and "SUMMARY OF CERTAIN PROVISIONS OF THE RESOLUTION – Annual Budget" in Appendix A to the 2023 Annual Filing.

The Agency allocates the minimum cost component of Monthly Power Costs among the Generation Station, the Northern Transmission System and the Southern Transmission System in accordance with an Operating Cost Allocation Procedure approved by the Coordinating Committee and the Agency's Board of Directors. Under the Power Sales Contracts, the amount of Monthly Power Costs to be paid by each Power Purchaser for any month is the sum of: (i) its Generation Cost Share times the minimum cost component for such month allocated to the Generation Station; (ii) its Northern Transmission Cost Share, if any, times the minimum cost component for such month allocated to the Northern Transmission System; (iii) its Southern Transmission Cost Share, if any, times the minimum cost component for such month allocated to the Southern Transmission System; and (iv) the percentage of the energy delivered from the Project to it during the preceding month times the variable cost component. See "FISCAL YEAR 2024-2025 ANNUAL BUDGET" in APPENDIX A hereto.

On May 22, 2000, the Coordinating Committee adopted by resolution a "Fuel Acquisition and Transportation Cost Billing Procedure for Fiscal Year 2000-2001 and Thereafter" (the "Billing Procedure"). Pursuant to the Billing Procedure, the Coordinating Committee has taken the following actions with respect to the 2000-2001 fiscal year and each fiscal year thereafter and the Agency intends to continue to take such actions unless and until the Billing Procedure is repealed or modified to provide otherwise: (i) approved, pursuant to the authority delegated to the Coordinating Committee under the Power Sales Contracts, the inclusion in the minimum cost component of Monthly Power Costs of the minimum or guaranteed payments that the Agency is required to make under certain coal purchase contracts to which it is a party; (ii) directed that there be included in the variable cost component, rather than the minimum cost component, of Monthly Power Costs, transportation costs with respect to coal the cost of which is included in the variable cost component of Monthly Power Costs; (iii) approved a procedure for billing the variable cost component of Monthly Power Costs based upon the energy produced by the burning of coal the cost of which is included in the variable cost component; and (iv) approved a procedure permitting any Power Purchaser, to the extent that it does not schedule all of the energy produced by the burning of the coal the cost of which is included in its pro rata share of the minimum cost component of Monthly Power Costs during a particular month (an "Underburn Energy Balance"), to "bank" such energy for scheduling during subsequent months of the same fiscal year. From time to time subsequent to its adoption of the Billing Procedure, the Coordinating Committee has elected, pursuant to the Power Sales Contracts, to treat for billing purposes other coal purchase contracts to which the Agency is a party in the same manner as those referenced in the immediately preceding clause (i).

On August 21, 2012, the Coordinating Committee amended the Billing Procedure to make technical changes and to permit each Power Purchaser to "bank" an Overburn Energy Balance. The amendment provides that an "Overburn Energy Balance" is equal to the amount by which the energy scheduled by such Power Purchaser for a month exceeds the energy produced by the burning of the coal the cost of which is included in its pro rata share of the minimum cost component of Monthly Power Costs during such month. Each Power Purchaser may apply its Overburn Energy Balance to the extent of such balance to offset, during the same fiscal year in which such Overburn Energy Balance accrued, any future Underburn Energy Balance.

Year-End Reconciliation. Within 120 days after the end of each Power Supply Year, the Agency is required to submit to each Power Purchaser a statement of the actual aggregate Monthly Power Costs and other amounts payable under the Power Sales Contracts for all months of such year and any adjustments to such costs and amounts for any prior year, based on the annual audit required by the Power Sales Contracts. If for any Power Supply Year the actual aggregate Monthly Power Costs and other amounts payable under the Power Sales Contracts exceed the amount which the Power Purchasers have been billed, the Power Purchasers shall promptly pay the amount of such excess to the Agency. If such costs and other amounts, for any Power Supply Year, are less than the amounts billed, the Agency will credit the excess against the Power Purchasers' next monthly payments.

See "SUMMARY OF CERTAIN PROVISIONS OF THE POWER SALES CONTRACTS" in Appendix B to the 2023 Annual Filing.

Renewal Power Sales Contracts

General. Under the Renewal Power Sales Contracts, from and after the Transition Date, the Renewal Power Purchasers are entitled to Project (as defined in the Renewal Power Sales Contracts) generation and transmission capabilities based on their respective Generation Entitlement Shares and transmission entitlements and are obligated to make payments therefor.

Each Renewal Power Sales Contract between the Agency and a Renewal Power Purchaser constitutes an obligation of the parties until the terms of all of the Renewal Power Sales Contracts expire on June 16, 2077. As long as any Bonds or Subordinated Indebtedness is outstanding or until provision has been made for the payment of all outstanding Bonds and Subordinated Indebtedness, the Renewal Power Sales Contracts may not be terminated or amended in any manner which will reduce the amount of, or extend the time for, the payments that are pledged as security for Bonds and Subordinated Indebtedness or which will impair or adversely affect the rights of the holders of Bonds or Subordinated Indebtedness.

Payments are to be made by the Renewal Power Purchasers on a "take-or-pay" basis. The payment obligations under the Renewal Power Sales Contracts constitute operating expenses of the respective Renewal Power Purchasers payable solely from their electric revenue funds.

Each Renewal Power Purchaser has covenanted in its Renewal Power Sales Contract, from and after the Transition Date, to establish, maintain and collect rates and charges for the electric service it furnishes sufficient to provide revenues which, together with its available electric system reserves and other available funds, are adequate to enable it to pay to the Agency all amounts payable under its Power Sales Contract and to pay all other amounts payable from, and all liens on and lawful charges against, its electric system revenues. See "SUMMARY OF CERTAIN PROVISIONS OF THE RENEWAL POWER SALES CONTRACTS – Nature of Obligation" in Appendix B to the 2023 Annual Filing.

The Renewal Power Sales Contracts provide that the obligations of the respective Power Purchasers are several and not joint except for failure to pay money pursuant to a provision of a Renewal Power Sales Contract. A failure by a Renewal Power Purchaser to make payments when due under its Renewal Power Sales Contract may result in larger payments being made by the other Renewal Power Purchasers in subsequent periods for the purpose of enabling the Agency to pay operating expenses, debt service and other costs of the Project and to maintain required reserves therefor. To the extent the amount to be paid by the non-paying Renewal Power Purchaser is not offset by revenues from sales of power or transmission service derived by the Agency in respect of such non-paying Renewal Power Purchaser's Generation Entitlement Share or transmission entitlement, such non-payment may result in deficits in funds and accounts established under the Resolution. In such event, the Agency would be required to amend, in accordance with the Renewal Power Sales Contracts and the Resolution, the Annual Budget (as defined in the Renewal Power Sales Contracts) to provide increases in subsequent billings to all Renewal Power Purchasers, including the non-paying Renewal Power Purchaser, equal to the amount of such deficiency. Such increased billings are not conditioned upon any transfer of the non-paying Renewal Power Purchaser's Generation Entitlement Share or transmission entitlement to the other Renewal Power Purchasers. Amounts thereafter collected from such non-paying Renewal Power Purchaser are to be credited against the next billings of such other Renewal Power Purchasers as appropriate.

In the event of a default or inability to perform by a Renewal Power Purchaser under its Renewal Power Sales Contract, the Agency may proceed to enforce the Renewal Power Purchaser's covenants or obligations thereunder, or seek damages for the breach thereof, by action at law or in equity. The Renewal Power Sales Contracts also provide that if a payment due under the Renewal Power Sales Contracts remains unpaid when due, the Agency may, upon 120 days' written notice to the Renewal Power Purchaser, discontinue the delivery of capacity and energy to, and the use of Project facilities by, such Renewal Power Purchaser while the default continues. Except as a result of a transfer of the defaulting Renewal Power Purchaser's rights to delivery of capacity and energy and the use of Project facilities, the discontinuance by the Agency of delivery of capacity and energy to and the use of the Project facilities by a defaulting Renewal Power Purchaser will not reduce the obligation of such Renewal Power Purchaser to make payments under its Renewal Power Sales Contract. For information regarding certain acts adopted by the California Legislature in recent years that may limit the Agency's ability to sell or otherwise transfer a defaulting Renewal Power Purchaser's Generation Entitlement Share or electric energy attributable thereto to California investor-owned or publicly-owned electric utilities to recover lost revenues resulting from such default, see "ENVIRONMENTAL AND HEALTH FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY – Regulation of Greenhouse Gases – *Federal and California Greenhouse Gas Initiatives*" in the 2023 Annual Filing.

See "SUMMARY OF CERTAIN PROVISIONS OF THE RENEWAL POWER SALES CONTRACTS" in Appendix B to the 2023 Annual Filing.

Monthly Power Costs. During each Power Supply Year (as defined in the Renewal Power Sales Contracts) occurring from and after the Transition Date, each Renewal Power Purchaser is obligated to pay its share of Monthly Power Costs (as defined in the Renewal Power Sales Contracts), which, generally, consist of all of the Agency's costs resulting from the ownership, operation and maintenance of, and renewals and replacements to, the Project, to the extent not paid from the proceeds of Bonds and Subordinated Indebtedness or from notes or other evidences of indebtedness issued in anticipation thereof. Such costs, which consist of a minimum cost component and a variable cost component, are billed monthly. Power Supply Years coincide with the Agency's fiscal years, which, from and after the Transition Date, end on June 30.

The minimum cost component is to be billed each month occurring from and after the Transition Date for the then current month based on the estimates contained in the Annual Budget prepared by the Agency prior to the beginning of each Power Supply Year, as such Annual Budget may be amended during such year. For each such month, the minimum cost component includes:

(i) the amounts which the Resolution requires the Agency to pay or deposit during such month into funds or accounts for debt service on, and reserve requirements for, Bonds and Subordinated Indebtedness;

(ii) one-twelfth of the amount which the Agency is required under the Resolution to pay or deposit during the Power Supply Year which includes such month into any other fund or account established by the Resolution, including any amount needed to eliminate a deficiency in any fund established under the Resolution whether or not resulting from a default in payments by any Renewal Power Purchaser of amounts due under any Renewal Power Sales Contract;

(iii) one-twelfth of the costs of producing and delivering capacity and energy from the Project during the Power Supply Year which includes such month, including ordinary operation and maintenance costs, costs of water, overhead and certain fixed costs of natural gas procured by the Agency for use in the Generation Station (as defined in the Renewal Power Sales Contracts) ("Project Fuel") (but excluding, from the Monthly Power Costs of Renewal Power Purchasers who elect to procure their own fuel, minimum or guaranteed contract payments that the Renewal Contract Coordinating Committee has determined to include in the minimum cost component and excluding for such procuring Renewal Power Purchasers the transportation costs for Project Fuel); and

(iv) one-twelfth of the amount necessary during the Power Supply Year which includes such month to pay or provide reserves for payment of amounts required to be paid pursuant to the Act to counties, municipalities and school districts affected by the Project, Tax Equivalent Payments (as defined in the Renewal Power Sales Contracts) and all other taxes which the Agency is required to pay.

The variable cost component is to be billed each month for the immediately preceding month occurring from and after the Transition Date. The variable cost component of Monthly Power Costs consists of all costs of Project Fuel that was used to generate a Renewal Power Purchaser's Generation Entitlement Share and that was not included in the minimum cost component.

If there is any revision of the Annual Budget after the commencement of any Power Supply Year occurring from and after the Transition Date, the amounts determined pursuant to clauses (ii), (iii) and (iv) above are to be appropriately adjusted to evenly apportion any increase or decrease over the remaining months of such Power Supply Year. Subject to the election by Renewal Power Purchasers to procure their own fuel and any modifications provided in the Fuel Management Practices and Procedures (as defined in the Renewal Power Sales Contracts), as described below, the Agency anticipates following the same budgeting process from and after the Transition Date as that described in "Budgeting" below and "SUMMARY OF CERTAIN PROVISIONS OF THE RESOLUTION – Annual Budget" in Appendix A to the 2023 Annual Filing.

The Agency is to allocate the minimum cost component of Monthly Power Costs among the Generation Station (as defined in the Renewal Power Sales Contracts), the Northern Transmission System (as defined in the Renewal Power Sales Contracts) and the Southern Transmission System (as defined in the Renewal Power Sales Contracts) in accordance with the Renewal Power Sales Contracts. Under the Renewal Power Sales Contracts, the amount of Monthly Power Costs to be paid by each Power Purchaser for any month occurring from and after the Transition Date is the sum of: (i) its Generation Cost Share times the minimum cost component for such month allocated to the Generation Station; (ii) its Northern Transmission Cost Share, if any, times the minimum cost component for such month allocated to the Northern Transmission System; (iii) its Southern Transmission Cost Share, if any, times the minimum cost component for such month allocated to the Southern Transmission System; and (iv) the percentage of the energy delivered from the Project to it during the preceding month times the variable cost component.

The Renewal Power Sales Contracts contemplate the adoption of Fuel Management Practices and Procedures (as defined in the Renewal Power Sales Contracts). To the extent that any of the Fuel Management Practices and Procedures modifies the payment responsibility of any of the Renewal Power Purchasers for costs of Project Fuel acquisition or the costs of Project Fuel transmission or transportation, as then determined under the Renewal Power Sales Contracts, then such modification would require affirmation by Renewal Contract Coordinating Committee representatives of Purchasers having Voting Rights (as defined in the Renewal Power Sales Contracts) equal to 100%. The Renewal Contract Coordinating Committee approved the Hydrogen Billing Procedure as part of the Fuel Management Practices and Procedures.

Year-End Reconciliation. Within 120 days after the end of each Power Supply Year, the Agency is required to submit to each Renewal Power Purchaser a statement of the actual aggregate Monthly Power Costs and other amounts payable under the Renewal Power Sales Contracts for all months of such year and any adjustments to such costs and amounts for any prior year, based on the annual audit required by the Renewal Power Sales Contracts. If for any Power Supply Year the actual aggregate Monthly Power Costs and other amounts payable under the Renewal Power Sales Contracts exceed the amount which the Renewal Power Purchasers have been billed, the Renewal Power Purchasers shall promptly pay the amount of such excess to the Agency. If such costs and other amounts, for any Power Supply Year, are less than the amounts billed, the Agency will credit the excess against the Renewal Power Purchasers' next monthly payments.

See "SUMMARY OF CERTAIN PROVISIONS OF THE RENEWAL POWER SALES CONTRACTS" in Appendix B to the 2023 Annual Filing.

Excess Power Sales Agreement

Because a portion of the capability of the Project purchased by the Utah Purchasers was expected to be surplus to their needs, these Power Purchasers each entered into the Excess Power Sales Agreement in 1980, pursuant to which they may sell their respective excess Generation Entitlement Shares to the Excess Power Purchasers. Payments by the Excess Power Purchasers under such agreement are to be made monthly to Utah Associated Municipal Power Systems ("UAMPS"), successor to Intermountain Consumer Power Association ("ICPA"), as agent for the sellers under the Excess Power Sales Agreement, and forwarded promptly by it to the Agency for the accounts of the respective sellers. The Excess Power Sales Agreement does not reduce or modify the obligations of such Utah Purchasers under their Power Sales Contracts.

See "INTRODUCTORY STATEMENT – The Power Purchasers and the Renewal Power Purchasers" above for a discussion of certain recalls of Project capability made by certain of the Utah Purchasers and the status of the entitlements to Project capability of the remaining Utah Purchasers.

For a discussion of certain additional provisions of the Excess Power Sales Agreement, including those relating to adjustments of the amounts of capacity sold thereunder, see "SUMMARY OF CERTAIN PROVISIONS OF THE EXCESS POWER SALES AGREEMENT" in Appendix B to the 2023 Annual Filing.

Agreement for Sale of Renewal Excess Power

Because a portion of the capability of the Project (as defined in the Renewal Power Sales Contracts) purchased by the Utah Purchasers (as defined in the Renewal Power Sales Contracts) was expected still to be surplus to their needs from and after the Transition Date, these Renewal Power Purchasers each entered into the Agreement for Sale of Renewal Excess Power in 2017, pursuant to which they may sell their respective excess Generation Entitlement Shares to the Department. Payments by the Department under such agreement are to be made monthly to the Agency, as agent for the sellers under the Agreement for Sale of Renewal Excess Power, for the accounts of the respective sellers. The Agreement for Sale of Renewal Excess Power does not reduce or modify the obligations of such Utah Purchasers under their Renewal Power Sales Contracts.

The Agreement for Sale of Renewal Excess Power permits the Utah Purchasers to recall all or a portion of the entitlement that they have sold to the Department. Recalls under the Agreement for Sale of Renewal Excess Power are made with respect to a "Summer Season" or a "Winter Season" (each a "Season"). The Agreement for Sale of Renewal Excess Power defines a "Summer Season" as each period beginning at 12:01 a.m. on June 1 and ending at 12:01 a.m. on the following October 1 and a "Winter Season" as each period beginning at 12:01 a.m. on October 1 and ending at 12:01 a.m. on the following June 1.

Based on the current schedules of power to be sold under the Agreement for Sale of Renewal Excess Power, which schedules are to be revised, if at all, at least twelve months prior to the Transition Date and, thereafter, upon notice to be provided at least twelve months prior to the commencement of any Season, the Utah Purchasers have elected to sell to the Department, commencing on the Transition Date, all of their Project capability. Any election by a Utah Purchaser to sell such Project capability must remain in effect for three calendar years following the commencement of the Season with respect to which such election has been made. The Utah Purchasers may recall all or a portion of such Project capability over the course of at least two calendar years following the expiration of such three-calendar-year period.

For a discussion of certain additional provisions of the Agreement for Sale of Renewal Excess Power, including those relating to adjustments of the amounts of capacity sold thereunder, see "SUMMARY OF CERTAIN PROVISIONS OF THE AGREEMENT FOR SALE OF RENEWAL EXCESS POWER" in Appendix B to the 2023 Annual Filing.

Budgeting

The Power Sales Contracts and, from and after the Transition Date, the Renewal Power Sales Contracts require the Agency to adopt an Annual Budget at least 30 days but not more than 45 days prior to the beginning of each Power Supply Year (as defined, prior to the Transition Date, in the Power Sales Contracts and, from and after the Transition Date, in the Renewal Power Sales Contracts) and permit the amendment of the Annual Budget (as defined, prior to the Transition Date, in the Power Sales Contracts and, from and after the Transition Date, the Renewal Power Sales Contracts) from time to time thereafter. Each such budget is to set forth a detailed estimate of the Monthly Power Costs and all Revenues, income or other funds to be applied to such costs, for and applicable to such Power Supply Year. See "Power Sales Contracts" above. The Resolution requires the Agency to adopt Annual Budgets, and amendments to such Annual Budgets, as and when required by the Power Sales Contracts. See "FISCAL YEAR 2024-2025 ANNUAL BUDGET" in APPENDIX A hereto.

Generation Renewal Project

To facilitate the continued involvement of the California Purchasers in the Project following the termination of the Power Sales Contracts (provided to occur on June 15, 2027), the Agency and each of the Power Purchasers amended the Power Sales Contracts to provide for the Gas Repowering. The Power Sales Contracts, as so amended, provide for the Gas Repowering to be completed by July 1, 2025. The Power Sales Contracts, as so amended, also provide that the costs of retiring and decommissioning facilities of the Project that are not used in the Gas Repowering are to be funded through indebtedness to be incurred by the Agency in connection with the Gas Repowering.

As a condition to proceeding with the Gas Repowering, pursuant to Section 44 of the Power Sales Contracts, the Coordinating Committee and the Agency adopted a plan for retirement and decommissioning of facilities of the Project not expected to be used in connection with the Gas Repowering (as described in the Power Sales Contracts, the "Section 44 Retirement Plan"). The Section 44 Retirement Plan provides for the retirement and decommissioning of Agency assets as soon as July 2025, following the cessation of operations at the existing Intermountain Generation Station. Legislation enacted in 2023 by the Utah legislature purports to restrict the decommissioning of Agency assets constituting the Agency's coal-powered electrical generation facility. See "ELECTRIC INDUSTRY RESTRUCTURING – Utah Electric Energy Actions – *H.B. 425*" in the 2023 Annual Filing.

Section 45 of the Power Sales Contracts, as so amended, further provides that in the event the Gas Repowering is not undertaken as provided in the Power Sales Contracts, and there is no Transition Project Indebtedness, as defined in the Power Sales Contracts, outstanding, the Project would consist of transmission facilities with sufficient generation capacity to support such transmission facilities. The entitlements to such facilities would be sold to the Power Purchasers who elect to renew their entitlements in the Project pursuant to a transmission services agreement. The California Renewal Purchasers would be offered 100% of the entitlements in the Southern Transmission System and 60% of the entitlements in the Northern Transmission System. The Utah Renewal Purchasers would be offered 40% of the entitlements in the Northern Transmission System. The term of the Power Sales Contracts would be extended to the earlier of the completion of decommissioning and retirement of the facilities not necessary to maintain and support such transmission facilities and January 1, 2032. In that event, the Renewal Power Sales Contracts and the Agreement for Sale of Renewal Excess Power would terminate.

The 2024 Series A and B Bonds will constitute Transition Project Indebtedness. Accordingly, the Agency believes that the provisions of Section 45 of the Renewal Power Sales Contracts will not become operative.

See "INTRODUCTORY STATEMENT – The Project and the Generation Renewal Project" and "SECURITY AND SOURCES OF PAYMENT FOR THE 2024 SERIES A AND B BONDS – Power Sales Contracts" and "– Excess Power Sales Agreement" above, "ELECTRIC INDUSTRY RESTRUCTURING – California Electric Energy Actions," "ENVIRONMENTAL AND HEALTH FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY – Regulation of Greenhouse Gases" and "INTERMOUNTAIN POWER AGENCY – The Interlocal Cooperation Act" in the 2023 Annual Filing and "SUMMARY OF CERTAIN PROVISIONS OF THE POWER SALES CONTRACTS" and "SUMMARY OF CERTAIN PROVISIONS OF THE EXCESS POWER SALES AGREEMENT" in Appendix B to the 2023 Annual Filing.

Hydrogen Facilities

The Agency has contracted for the Hydrogen Facilities which consist of (a) the Hydrogen Betterments that are expected to minimize the costs associated with increasing the capabilities of the gas units to burn a fuel mix including green hydrogen, and (b) the Hydrogen Conversion and Storage Capacity to provide hydrogen fuel production and storage for use in connection with the Hydrogen Betterments. See "INTRODUCTORY STATEMENT – Hydrogen Facilities" above.

Other Amendments to Material Contracts

The Agency and the Department have negotiated the amendment and restatement of the Construction Management and Operating Agreement for changes required as a result of the amendment of the Power Sales Contracts and the execution of the Renewal Power Sales Contracts as well as other changes that are desirable to update the relationship between the Agency and the Department, in the Department's capacities as Project Manager and Operating Agent. Such amendment and restatement is in the process of receiving approval of the necessary governing bodies of the Department. See "SUMMARY OF CERTAIN PROVISIONS OF THE CONSTRUCTION MANAGEMENT AND OPERATING AGREEMENT" in Appendix B to the 2023 Annual Filing.

The Agency has amended its organizational documents from time to time to extend the Agency's existence, to facilitate the Generation Renewal Project and to update such documents to conform to changes in Utah law.

DESCRIPTION OF THE 2024 SERIES A AND B BONDS

General

The 2024 Series A Bonds will be issued in the aggregate principal amount of $161,215,000 and the 2024 Series B Bonds will be issued in the aggregate principal amount of $13,785,000. The 2024 Series A and B Bonds will be dated the date of the delivery thereof, and will bear interest from that date payable on January 1, 2025 and each January 1 and July 1 thereafter until maturity or prior redemption. Interest shall be calculated on the basis of a 360-day year consisting of twelve 30-day months. The 2024 Series A and B Bonds will mature on July 1 in the years and the principal amounts and bear interest at the rates set forth on the inside front cover of this Official Statement. The 2024 Series A and B Bonds will be issuable only in fully registered form in the principal amount of $5,000 and integral multiples thereof. Upon initial issuance, the 2024 Series A and B Bonds will be issued in book-entry only form and will be registered in the name of Cede & Co., as nominee for DTC. See "Book-Entry Only System" below.

The principal or redemption price of the 2024 Series A and B Bonds will be payable at the principal office of the Paying Agent and interest on any 2024 Series A and B Bond will be paid on each interest payment date to the person in whose name such Bond is registered on the applicable Record Date, which is the close of business on the fifteenth (15th) day (whether or not a business day) of the calendar month next preceding such interest payment date; *provided*, *however*, that so long as the 2024 Series A and B Bonds are subject to the book-entry only system of registration and transfer described in "Book-Entry Only System" below, all payments with respect to the principal or redemption price of, and interest on, the 2024 Series A and B Bonds will be made to DTC.

Book-Entry Only System

General

The 2024 Series A and B Bonds will be available only in book-entry form. DTC will act as the initial securities depository for the 2024 Series A and B Bonds. The 2024 Series A and B Bonds will be issued as fully-registered securities registered in the name of Cede & Co. (DTC's partnership nominee) or such other name as may be requested by an authorized representative of DTC. One fully-registered bond certificate will be issued in the aggregate principal amount of the 2024 Series A and B Bonds of each maturity (and, if applicable, each interest rate within a maturity), and will be deposited with DTC.

DTC, the world's largest securities depository, is a limited-purpose trust company organized under the New York Banking Law, a "banking organization" within the meaning of the New York Banking Law, a member of the Federal Reserve System, a "clearing corporation" within the meaning of the New York Uniform Commercial Code, and a "clearing agency" registered pursuant to the provisions of Section 17A of the Securities Exchange Act of 1934. DTC holds and provides asset servicing for over 3.5 million issues of U.S. and non-U.S. equity issues, corporate and municipal debt issues, and money market instruments (from over 100 countries) that DTC's participants ("Direct Participants") deposit with DTC. DTC also facilitates the post-trade settlement among Direct Participants of sales and other securities transactions in deposited securities, through electronic computerized book-entry transfers and pledges between Direct Participants' accounts. This eliminates the need for physical movement of securities certificates. Direct Participants include both U.S. and non-U.S. securities brokers and dealers, banks, trust companies, clearing corporations, and certain other organizations. DTC is a wholly-owned subsidiary of The Depository Trust & Clearing Corporation ("DTCC"). DTCC is the holding company for DTC, National Securities Clearing Corporation and Fixed Income Clearing Corporation, all of which are registered clearing agencies. DTCC is owned by the users of its regulated subsidiaries. Access to the DTC system is also available to others such as both U.S. and non-U.S. securities brokers and dealers, banks, trust companies, and clearing corporations that clear through or maintain a custodial relationship with a Direct Participant, either directly or indirectly ("Indirect Participants"). DTC has a Standard &

Poor's rating of AA+. The DTC Rules applicable to its Participants are on file with the SEC. More information about DTC can be found at www.dtcc.com.

Purchases of 2024 Series A and B Bonds under the DTC system must be made by or through Direct Participants, which will receive a credit for such Bonds on DTC's records. The ownership interest of each actual purchaser of each 2024 Series A and 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 ownership interests in the 2024 Series A and 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 ownership interests in 2024 Series A and B Bonds, except in the event that use of the book-entry system for the 2024 Series A and B Bonds is discontinued.

SO LONG AS CEDE & CO. (OR ANY OTHER NOMINEE REQUESTED BY DTC) IS THE REGISTERED OWNER OF THE 2024 SERIES A AND B BONDS, AS NOMINEE FOR DTC, REFERENCES HEREIN TO THE HOLDERS OR REGISTERED OWNERS OR OWNERS OF THE 2024 SERIES A AND B BONDS WILL MEAN CEDE & CO. (OR SUCH OTHER NOMINEE), AS AFORESAID, AND WILL NOT MEAN THE BENEFICIAL OWNERS.

To facilitate subsequent transfers, all 2024 Series A and 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 2024 Series A and B Bonds with DTC and their registration in the name of Cede & Co. or such other DTC nominee do not effect any change in beneficial ownership. DTC has no knowledge of the actual Beneficial Owners of the 2024 Series A and B Bonds; DTC's records reflect only the identity of the Direct Participants to whose accounts such 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.

The Agency, the Trustee and the Bond Registrar and Paying Agent for the 2024 Series A and B Bonds may treat DTC (or its nominee) as the sole and exclusive owner of the 2024 Series A and B Bonds registered in its name for the purpose of: payment of the principal or redemption price of or interest on the 2024 Series A and B Bonds; giving any notice permitted or required to be given to Holders under the Resolution, including any notice of redemption; registering the transfer of 2024 Series A and B Bonds; obtaining any consent or other action to be taken by Holders; and for all other purposes whatsoever, and shall not be affected by any notice to the contrary. Neither the Agency nor the Trustee nor the Bond Registrar nor the Paying Agent for the 2024 Series A and B Bonds nor the Underwriters (other than in their capacity, if any, as Direct Participants or Indirect Participants) will have any responsibility or obligation to any Direct Participant, any person claiming a beneficial ownership interest in the 2024 Series A and B Bonds under or through DTC or any Direct Participant, or any other person which is not shown on the registry books of the Agency (kept by the Bond Registrar for the 2024 Series A and B Bonds) as being a Holder, with respect to: the accuracy of any records maintained by DTC or any Direct or Indirect Participant regarding ownership interests in the 2024 Series A and B Bonds; the payment by DTC or any Direct or Indirect Participant of any amount in respect of the principal or redemption price of or interest on the 2024 Series A and B Bonds; the delivery to any Direct or Indirect Participant or any Beneficial Owner of any notice which is permitted or required to be given to Holders under the Resolution including any notice of redemption; the selection by DTC or any Direct or Indirect Participant of any person to receive payment in the event of a partial redemption of the 2024 Series A or B Bonds; or any consent given or other action taken by DTC as a Holder of the 2024 Series A and B Bonds.

Neither DTC nor Cede & Co. (nor any other DTC nominee) will consent or vote with respect to 2024 Series A and B Bonds unless authorized by a Direct Participant in accordance with DTC's Money Market Instrument (MMI) Program and Procedures. Under its usual procedures, DTC mails an Omnibus Proxy to the issuer as soon as possible after the "record date." The Omnibus Proxy assigns Cede & Co.'s consenting or voting rights to those Direct Participants to whose accounts securities, such as the 2024 Series A and B Bonds, are credited on the record date (identified in a listing attached to the Omnibus Proxy).

Except as described below, neither DTC nor Cede & Co. nor any other nominee of DTC will take any action to enforce covenants with respect to any security registered in the name of Cede & Co. or any other nominee of DTC. Under its current procedures, on the written instructions of a Direct Participant given in accordance with DTC's procedures, DTC will cause Cede & Co. to sign a demand to exercise certain bondholder rights. In accordance with DTC's current procedures, Cede & Co. will sign such document only as record holder of the quantity of securities referred to therein (which is to be specified in the Direct Participant's request to DTC for such document) and not as record holder of all the securities of that issue registered in the name of Cede & Co. Also, in accordance with DTC's current procedures, all factual representations to the issuer or any other party to be made by Cede & Co. in such document must be made to DTC and Cede & Co. by the Direct Participant in its request to DTC.

For so long as the 2024 Series A and B Bonds are issued in book-entry form through the facilities of DTC, any Beneficial Owner desiring to cause the Agency to comply with any of its obligations with respect to the 2024 Series A and B Bonds must make arrangements with the Direct Participant or Indirect Participant through whom such Beneficial Owner's ownership interest in the 2024 Series A and B Bonds is recorded in order for the Direct Participant in whose DTC account such ownership interest is recorded to make the request of DTC described above.

NEITHER THE AGENCY NOR THE TRUSTEE NOR THE BOND REGISTRAR NOR THE PAYING AGENT FOR THE 2024 SERIES A AND B BONDS NOR THE UNDERWRITERS (OTHER THAN IN THEIR CAPACITY, IF ANY, AS DIRECT PARTICIPANTS OR INDIRECT PARTICIPANTS) WILL HAVE ANY OBLIGATION TO THE DIRECT PARTICIPANTS OR THE INDIRECT PARTICIPANTS OR THE PERSONS FOR WHOM THEY ACT AS NOMINEES WITH RESPECT TO DTC'S PROCEDURES OR ANY PROCEDURES OR ARRANGEMENTS BETWEEN DIRECT PARTICIPANTS, INDIRECT PARTICIPANTS AND THE PERSONS FOR WHOM THEY ACT RELATING TO THE MAKING OF ANY DEMAND BY CEDE & CO. AS THE REGISTERED OWNER OF THE 2024 SERIES A AND B BONDS, THE ADHERENCE TO SUCH PROCEDURES OR ARRANGEMENTS OR THE EFFECTIVENESS OF ANY ACTION TAKEN PURSUANT TO SUCH PROCEDURES OR ARRANGEMENTS.

Principal or redemption price of and interest on the 2024 Series A and B Bonds will be paid to Cede & Co., or such other nominee as may be requested by an authorized representative of DTC. DTC's practice is to credit Direct Participants' accounts upon DTC's receipt of funds and corresponding detail information from the Agency or the Paying Agent, 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 Agency or the Paying Agent for the 2024 Series A and B Bonds, subject to any statutory or regulatory requirements as may be in effect from time to time. Payment of principal or redemption price and interest to Cede & Co. (or such other nominee as may be requested by an authorized representative of DTC) is the responsibility of the Paying Agent for the 2024 Series A and B Bonds, 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.

As long as the book-entry system is used for the 2024 Series A and B Bonds, the Bond Registrar for the 2024 Series A and B Bonds will give any notice of redemption or any other notices required to be given to Holders of 2024 Series A and B Bonds only to DTC. Any failure of DTC to advise any Direct Participant, or of any Direct Participant to notify any Indirect Participant, or of any Direct or Indirect Participant to notify any Beneficial Owner, of any such notice and its content or effect will not affect the validity of the redemption of the 2024 Series A or B Bonds called for such redemption, or of any action premised on such notice.

Conveyance of notices and other communications by DTC to Direct Participants, by Direct Participants to Indirect Participants, and by Direct Participants and Indirect Participants to Beneficial Owners will be governed by arrangements among them, subject to any statutory or regulatory requirements as may be in effect from time to time. Beneficial Owners of 2024 Series A and B Bonds may wish to take certain steps to augment the transmission to them of notices of significant events with respect to the 2024 Series A and B Bonds, such as redemptions, tenders, defaults, and proposed amendments to the Resolution. For example, Beneficial Owners of the 2024 Series A and B Bonds may wish to ascertain that the nominee holding the 2024 Series A and B Bonds for their benefit has agreed to obtain and transmit notices to Beneficial Owners.

As long as the book-entry system is used for the 2024 Series A and B Bonds, redemption notices will be sent only to DTC. If less than all of the 2024 Series A or B Bonds of a particular maturity (or, if applicable, an interest rate within a maturity) are being redeemed, DTC's practice is to determine by lot the amount of the interest of each Direct Participant in the 2024 Series A or B Bonds of such maturity (or, if applicable, such interest rate within such maturity) to be redeemed.

NEITHER THE AGENCY NOR THE TRUSTEE NOR THE BOND REGISTRAR NOR THE PAYING AGENT FOR THE 2024 SERIES A AND B BONDS NOR THE UNDERWRITERS (OTHER THAN IN THEIR CAPACITY, IF ANY, AS DIRECT PARTICIPANTS OR INDIRECT PARTICIPANTS) WILL HAVE ANY RESPONSIBILITY OR OBLIGATION TO SUCH DIRECT PARTICIPANTS, OR THE PERSONS FOR WHOM THEY ACT AS NOMINEES, WITH RESPECT TO THE PAYMENTS TO OR THE PROVIDING OF NOTICE FOR THE DIRECT PARTICIPANTS, THE INDIRECT PARTICIPANTS, OR THE BENEFICIAL OWNERS.

For every transfer and exchange of a beneficial ownership interest in the 2024 Series A and B Bonds, a Beneficial Owner may be charged a sum sufficient to cover any tax, fee or other governmental charge that may be imposed in relation thereto.

Discontinuation of the Book-Entry System

DTC may determine to discontinue providing its services as depository with respect to the 2024 Series A and B Bonds at any time by giving reasonable notice to the Agency or the Trustee. In addition, if the Agency determines that (i) DTC is unable to discharge its responsibilities with respect to the 2024 Series A and B Bonds, or (ii) continuation of the system of book-entry transfers through DTC is not in the best interests of the Beneficial Owners of the 2024 Series A and B Bonds or of the Agency, the Agency may, upon satisfaction of the applicable procedures of DTC with respect thereto, terminate the services of DTC with respect to the 2024 Series A and B Bonds. Upon the resignation of DTC or determination by the Agency that DTC is unable to discharge its responsibilities, the Agency may, within 90 days, appoint a successor depository. If no such successor is appointed or the Agency determines to discontinue the book-entry system, 2024 Series A and B Bond certificates will be printed and delivered. Transfers and exchanges of 2024 Series A and B Bonds will thereafter be made as described under "Interchangeability" below.

If the book-entry system is discontinued, the persons to whom 2024 Series A and B Bond certificates are delivered will be treated as "Holders" for all purposes of the Resolution, including without limitation the payment of principal or redemption price of, and interest on, 2024 Series A and B Bonds, the redemption of 2024 Series A or B Bonds and the giving to the Agency of any notice, consent, request or demand pursuant to the Resolution for any purpose whatsoever. In such event, interest on such 2024 Series A and B Bonds will be payable by check or draft of the Trustee, as the Paying Agent for the 2024 Series A and B Bonds, mailed to such Holders at the addresses shown on the registry books of the Agency kept for that purpose at the principal corporate trust office of the Trustee, as Bond Registrar for the 2024 Series A and B Bonds, and the principal and redemption price of all 2024 Series A and B Bonds will be payable at the principal corporate trust office of the Trustee, as the Paying Agent for the 2024 Series A and B Bonds.

The information in this section concerning DTC and DTC's book-entry system has been obtained from sources that the Agency believes to be reliable. No representation is made herein by the Agency or the Underwriters as to the accuracy, completeness or adequacy of such information, or as to the absence of material adverse changes in such information subsequent to the date of this Official Statement.

Redemption

Optional Redemption

***2024 Series A Bonds*.** The 2024 Series A Bonds maturing on or after July 1, 2034 are subject to redemption prior to maturity at the option of the Agency, as a whole or in part, at any time on or after July 1, 2033, at a redemption price equal to 100% of the principal amount of 2024 Series A Bonds or portions thereof to be redeemed, plus accrued interest to the redemption date.

***2024 Series B Bonds*.** The 2024 Series B Bonds maturing on or after July 1, 2034 are subject to redemption prior to maturity at the option of the Agency, as a whole or in part (and if in part on a *pro rata* basis), at any time on or after July 1, 2033, at a redemption price equal to 100% of the principal amount of 2024 Series B Bonds or portions thereof to be redeemed, plus accrued interest to the redemption date.

The 2024 Series B Bonds also are subject to redemption prior to maturity at the option of the Agency, as a whole or in part, at any time before July 1, 2033, in whole or in part (and if in part on a *pro rata* basis), on any Business Day (defined below), at the Make-Whole Redemption Price (defined below) determined by the Designated Investment Banker (defined below).

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 2024 Series B Bonds to be redeemed, or (2) the sum of the present values of the remaining scheduled payments of principal and interest on the 2024 Series B 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 2024 Series B Bonds are to be redeemed, discounted to the date on which such 2024 Series B 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 the number of basis points shown below, plus accrued and unpaid interest on the 2024 Series B Bonds to be redeemed on the redemption date.

Maturity (July 1)	Basis Points
2026 –2028	10
2029 –2034 and 2045	15

"*Business Day*" means (i) a day other than a day on which commercial banks located in New York, New York or cities in which the designated office of the Trustee or the Paying Agent for the 2024

Series A and B Bonds are required or authorized by law to close and (ii) a day other than a day on which the New York Stock Exchange is closed.

"*Comparable Treasury Issue*" means, with respect to any Valuation Date (defined below) for a redemption date for a particular 2024 Series B 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 2024 Series B 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 2024 Series B Bonds to be redeemed.

"*Comparable Treasury Yield*" means, with respect to any Valuation Date for a redemption date for a particular 2024 Series B 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 (5) Reference Treasury Dealer Quotations, the average of all such quotations.

"*Designated Investment Banker*" means one of the Reference Treasury Dealers appointed by the Agency.

"*Reference Treasury Dealer*" means each of five (5) firms, specified by the Agency from time to time, that are primary U.S. Government securities dealers in the City of New York (each, a "*Primary Treasury Dealer*"); *provided*, *however*, that if any of them ceases to be a Primary Treasury Dealer, the Agency will substitute another Primary Treasury Dealer.

"*Reference Treasury Dealer Quotations*" means, with respect to each Reference Treasury Dealer and any redemption date for a particular 2024 Series B Bond, the average, as determined by the Designated Investment Banker, of the bid and asked prices for the Comparable Treasury Issue (expressed in each case as a percentage of its principal amount) quoted in writing to the Agency and the Trustee by such Reference Treasury Dealer at 3:30 p.m. (New York City time) on the Valuation Date.

"*Treasury Rate*" means, with respect to any redemption date for a particular 2024 Series B 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 above), assuming that the Comparable Treasury Issue is purchased on the redemption date for a price equal to the Comparable Treasury Yield (defined above), as calculated by the Designated Investment Banker (defined above).

"*Valuation Date*" means a date that is no earlier than four (4) 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.

Sinking Fund Redemption – 2024 Series B Bonds

The 2024 Series B Bonds maturing on July 1, 2045 (the "2024 Series B 2045 Term Bonds") are subject to redemption through sinking fund installments on July 1 of each of the years set forth in the table below. The redemption price will be 100 percent of the principal amount of the 2024 Series B 2045 Term Bonds so to be redeemed plus accrued interest, if any, to the redemption date. Such sinking fund installments will be sufficient to redeem the following principal amounts of the 2024 Series B 2045 Term Bonds:

$9,255,000 2024 Series B 2045 Term Bonds

July 1	Principal Amount
2035	$ 635,000
2036	670,000
2037	705,000
2038	745,000
2039	785,000
2040	830,000
2041	875,000
2042	925,000
2043	975,000
2044	1,025,000
2045†	1,085,000

† Maturity

Selection of 2024 Series A and B Bonds to be Redeemed

2024 Series A Bonds. If less than all of the 2024 Series A Bonds are to be redeemed, the Agency may select the maturity or maturities to be redeemed. If less than all of the 2024 Series A Bonds of any maturity are to be redeemed, the particular 2024 Series A Bonds or portions of 2024 Series A Bonds of such maturity to be redeemed shall be selected at random by the Trustee in such manner as the Trustee in its discretion may deem fair and appropriate. The portion of any 2024 Series A Bond of a denomination of more than $5,000 to be redeemed will be in the principal amount of $5,000 or an integral multiple thereof, and in selecting portions of 2024 Series A Bonds for redemption, the Trustee will treat each 2024 Series A Bond as representing that number of 2024 Series A Bonds of $5,000 denomination which is obtained by dividing the principal amount of such 2024 Series A Bond to be redeemed in part by $5,000.

2024 Series B Bonds. If less than all of the 2024 Series B Bonds are called for optional redemption, the Agency will designate the maturities from which the 2024 Series B Bonds are to be redeemed. For so long as the 2024 Series B Bonds are registered in book-entry form and DTC or a successor securities depository is the sole registered owner of such 2024 Series B Bonds, if fewer than all of the 2024 Series B Bonds of the same maturity and bearing the same interest rate are to be redeemed, the particular 2024 Series B Bonds to be redeemed shall be selected on a *pro rata* pass-through distribution of principal basis 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, all 2024 Series B Bonds to be so redeemed will be selected for redemption in accordance with DTC procedures by lot; *provided*, *however*, that any such redemption must be performed such that all 2024 Series B Bonds remaining Outstanding will be in authorized denominations.

In connection with any payment of principal of the 2024 Series B Bonds pursuant to the pass-through distribution of principal as described above, the Trustee will direct DTC to make a pass-through distribution of principal to the beneficial owners of the 2024 Series B Bonds.

For purposes of calculating *pro rata* pass-through distributions of principal, "*pro rata*" means, for any amount of principal or interest to be paid, the application of a fraction to such amounts where (a) the numerator is equal to the amount due to the owners of the 2024 Series B Bonds on a payment date, and (b) the denominator is equal to the total original par amount of the 2024 Series B Bonds.

It is the Agency's intent that redemption allocations made by DTC with respect to the 2024 Series B Bonds be made on a *pro rata* pass-through distribution of principal basis as described above. However, the Agency cannot provide any assurance that DTC, DTC's direct and indirect participants, or any other intermediary will allocate the redemption of such 2024 Series B Bonds on such basis.

If the 2024 Series B Bonds are not registered in book-entry form and if fewer than all of the 2024 Series B Bonds of the same maturity and bearing the same interest rate are to be redeemed, the 2024 Series B Bonds of such maturity and bearing such interest rate to be redeemed will be selected on a *pro rata* basis; *provided*, *however*, that any such redemption must be performed such that all 2024 Series B Bonds remaining Outstanding will be in authorized denominations.

Notice of Redemption

The Resolution requires the Trustee to give notice of any redemption of the 2024 Series A and B Bonds by first class mail, postage prepaid, not less than 30 days nor more than 60 days prior to the redemption date, to the Holders of any 2024 Series A or B Bonds or portions of 2024 Series A or B Bonds which are to be redeemed, at their last addresses, if any, appearing upon the registry books of the Agency (kept by the Trustee, as Bond Registrar for the 2024 Series A and B Bonds), but failure to do so, or any defect in such notice, will not affect the validity of the proceedings for the redemption of any other 2024 Series A or B Bonds. Such notice will state that on the redemption date there will become due and payable upon each 2024 Series A or B Bond (or portion thereof) to be redeemed the redemption price thereof, together with interest accrued to the redemption date, and that from and after such date interest thereon will cease to accrue and be payable. In addition, such notice will state that (a) (if applicable) if such notice is revoked or ceases to be in effect in accordance with its terms or (b) if on the date fixed for redemption sufficient moneys are not available to pay such redemption price and interest, then such 2024 Series A or B Bonds (or portions thereof) will not become due and payable as aforesaid.

For so long as a book-entry system is in effect with respect to the 2024 Series A and B Bonds, the Trustee will mail notices of redemption of such 2024 Series A or B Bonds only to DTC or its nominee, or its successor, and if less than all of the 2024 Series A or B Bonds of a particular maturity (and, if applicable, any interest rate within such maturity) are to be redeemed, DTC or its successor and Direct Participants and Indirect Participants will determine the particular ownership interests of the 2024 Series A and B Bonds of such maturity (and, if applicable, such interest rate within such maturity) to be redeemed, as the registered owner thereof. Any failure of DTC or its successor or a Direct Participant or Indirect Participant to so select particular ownership interests of 2024 Series A or B Bonds to be redeemed, or to notify a Beneficial Owner of a 2024 Series A or B Bond of any redemption will not affect the sufficiency or the validity of the redemption of the 2024 Series A or B Bonds. See "Book-Entry System" above. Neither the Agency nor the Trustee nor the Underwriters (other than in their capacity, if any, as Direct Participants or Indirect Participants) can make any assurance that DTC, the Direct Participants or the Indirect Participants will distribute such redemption notices to the Beneficial Owners of the 2024 Series A and B Bonds, or that they will do so on a timely basis.

Interchangeability

If the book-entry system has been terminated with respect to the 2024 Series A and B Bonds, the 2024 Series A and B Bonds, upon surrender thereof at the principal corporate trust office of the Bond Registrar, with a written instrument of transfer satisfactory to the Bond Registrar, duly executed by the registered owner or the registered owner's duly authorized attorney, may be exchanged for an equal aggregate principal amount of the 2024 Series A or B Bonds, as applicable, of the same maturity (and, if applicable, interest rate within such maturity) of any authorized denominations.

In all cases in which the privilege of exchanging or transferring the 2024 Series A and B Bonds is exercised, the Agency will execute and the Bond Registrar for the 2024 Series A and B Bonds will authenticate and deliver replacement 2024 Series A or B Bonds, as applicable, in accordance with the provisions of the Resolution. For every such exchange or transfer of the 2024 Series A and B Bonds, the Agency or the Bond Registrar for the 2024 Series A and B Bonds may make a charge sufficient to reimburse it for any tax, fee or other governmental charge required to be paid with respect to such exchange or transfer, but may impose no other charge therefor. Neither the Agency nor the Bond Registrar for the 2024 Series A and B Bonds will be required (a) to transfer or exchange 2024 Series A and B Bonds for the period next preceding any interest payment date for the 2024 Series A and B Bonds beginning with the Record Date for such interest payment date and ending on such interest payment date, (b) to transfer or exchange 2024 Series A or B Bonds of a particular maturity for a period beginning 15 days before the mailing of any notice of redemption therefor and ending on the day of such mailing or (c) to transfer or exchange any 2024 Series A and B Bonds called for redemption, other than the unredeemed portion of any 2024 Series A or B Bond redeemed in part.

Tax Covenants

In order to maintain the exclusion from gross income for federal income tax purposes of interest on the 2024 Series A Bonds, and for no other purpose, the Agency has covenanted to comply with each applicable requirement of the Internal Revenue Code of 1986 necessary to maintain such exclusion. So long as necessary in order to maintain the exclusion from federal gross income of interest on the 2024 Series A Bonds, these covenants will survive the payment of the 2024 Series A Bonds and the interest thereon, including any payment or defeasance thereof pursuant to the Resolution. Any amounts required to be paid by the Agency to the federal government pursuant to these covenants will be Operating Expenses for purposes of the Resolution and the Agency may provide for any such payment in its Annual Budget.

DEBT SERVICE REQUIREMENTS

Set forth in APPENDIX D hereto is a table showing the debt service requirements for the 2022 Series A and B Bonds, the 2023 Series A and B Bonds and the 2024 Series A and B Bonds.

LITIGATION

At the time of delivery of the 2024 Series A and B Bonds, the Agency will certify that there is no litigation or other proceeding pending or, to the knowledge of the Agency, threatened in any court, agency or other administrative body (either state or federal) restraining or enjoining the authorization, issuance, sale or delivery of the 2024 Series A and B Bonds or the collection of Revenues, or in any way questioning or affecting: (i) the proceedings under which the 2024 Series A and B Bonds are to be issued, (ii) the validity of any provision of the 2024 Series A and B Bonds or the Resolution, (iii) the pledges by the Agency under the Resolution, (iv) the validity or enforceability of the Power Sales Contracts or the Renewal Power Sales Contracts or the Excess Power Sales Agreement or the Agreement for Sale of Renewal Excess Power or (v) the legal existence of the Agency or the title to office of the officers of the Agency.

For a description of certain litigation to which the Agency is a party, see the information under the caption “LITIGATION” in the 2023 Annual Filing.

RATINGS

Moody's has assigned a rating of "Aa3" and a stable ratings outlook to the 2024 Series A and B Bonds and Fitch has assigned a rating of "AA-" and a stable ratings outlook to the 2024 Series A and B Bonds.

The respective ratings and outlooks by Moody's and Fitch of the 2024 Series A and B Bonds reflect only the views of such organizations and any desired explanation of the significance of such ratings and outlooks or any other statements given by the rating agencies with respect thereto should be obtained from the rating agency furnishing the same, at the following addresses: Moody's Investors Service, 7 World Trade Center at 250 Greenwich Street, New York, New York 10007; and Fitch Ratings, One State Street Plaza, New York, New York 10004. Generally, a rating agency bases its rating and outlook (if any) on the information and materials furnished to it and on investigations, studies and assumptions of its own. There is no assurance that such ratings or outlooks will be in effect for any given period of time or that they will not be revised upward or downward or withdrawn entirely by such rating agencies if, in the judgment of such agencies, circumstances so warrant. Any such downward revision or withdrawal of any ratings may have an adverse effect on the market price of the 2024 Series A and B Bonds.

TAX MATTERS

2024 Series A Bonds

In the opinion of Orrick, Herrington & Sutcliffe LLP, New York, New York, Bond Counsel to the Agency ("Bond 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 2024 Series A Bonds is excluded from gross income for federal income tax purposes under Section 103 of the Internal Revenue Code of 1986 (the "Code"). Bond Counsel is of the further opinion that interest on the 2024 Series A Bonds is not a specific preference item for purposes of the federal individual alternative minimum tax. Bond Counsel observes that interest on the 2024 Series A Bonds included in adjusted financial statement income of certain corporations is not excluded from the federal corporate alternative minimum tax. Bond Counsel is also of the opinion that interest on the 2024 Series A Bonds is exempt from individual income taxes imposed by the State of Utah. Bond 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 2024 Series A Bonds. A complete copy of the proposed form of opinion of Bond Counsel is set forth as APPENDIX E hereto.

To the extent the issue price of any maturity of the 2024 Series A Bonds is less than the amount to be paid at maturity of such Bonds (excluding amounts stated to be interest and payable at least annually over the term of such 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 2024 Series A Bonds which is excluded from gross income for federal income tax purposes and is exempt from individual income taxes imposed by the State of Utah. For this purpose, the issue price of a particular maturity of the 2024 Series A Bonds is the first price at which a substantial amount of such maturity of the 2024 Series 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 2024 Series A Bonds accrues daily over the term to maturity of such Bonds on the basis of a constant interest rate compounded semiannually (with straight-line interpolations between compounding dates). The accruing original issue discount is added to the adjusted basis of such 2024 Series A Bonds to determine taxable gain or loss upon trade or business disposition (including sale, redemption, or payment on maturity) of such Bonds. Beneficial Owners of the 2024 Series A Bonds should consult their own tax advisors with respect to the tax consequences of ownership of 2024 Series A Bonds with original issue discount, including the treatment of Beneficial Owners who do not purchase such Bonds in the original offering to the public at the first price at which a substantial amount of such Bonds is sold to the public.

2024 Series 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 basis in a Premium Bond, will be reduced by the amount of amortizable bond premium properly allocable to such Beneficial Owner. Beneficial Owners of Premium Bonds should consult their own tax advisors with respect to the proper treatment of amortizable bond premium in their particular circumstances.

The Code imposes various restrictions, conditions and requirements relating to the exclusion from gross income for federal income tax purposes of interest on obligations such as the 2024 Series A Bonds. The Agency has made certain representations and covenanted to comply with certain restrictions, conditions and requirements designed to ensure that interest on the 2024 Series A Bonds will not be included in federal gross income (see "DESCRIPTION OF THE 2024 SERIES A AND B BONDS – Tax Covenants" herein). Inaccuracy of these representations or failure to comply with these covenants may result in interest on the 2024 Series A Bonds being included in gross income for federal income tax purposes, possibly from the date of original issuance of the 2024 Series A Bonds. The opinion of Bond Counsel assumes the accuracy of these representations and compliance with these covenants. Bond 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 Bond Counsel's attention after the date of issuance of the 2024 Series A Bonds may adversely affect the value of, or the tax status of interest on, the 2024 Series A Bonds. Accordingly, the opinion of Bond Counsel is not intended to, and may not, be relied upon in connection with any such actions, events or matters.

Although Bond Counsel is of the opinion that interest on the 2024 Series 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 2024 Series 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. Bond Counsel expresses no opinion regarding any such other tax consequences.

Current and future legislative proposals, if enacted into law, clarification of the Code or court decisions may cause interest on the 2024 Series 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 Code or court decisions may also affect, perhaps significantly, the market price for, or marketability of, the 2024 Series A Bonds. Prospective purchasers of the 2024 Series 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 Bond Counsel expresses no opinion.

The opinion of Bond Counsel is based on current legal authority, covers certain matters not directly addressed by such authorities, and represents Bond Counsel's judgment as to the proper treatment of the 2024 Series A Bonds for federal income tax purposes. It is not binding on the Internal Revenue Service (the "IRS") or the courts. Furthermore, Bond Counsel cannot give and has not given any opinion or assurance about the future activities of the Agency, or about the effect of future changes in the Code, the applicable regulations, the interpretation thereof or the enforcement thereof by the IRS. The Agency has covenanted, however, to comply with the requirements of the Code.

Bond Counsel's engagement with respect to the 2024 Series A Bonds ends with the issuance of the 2024 Series A Bonds, and, unless separately engaged, Bond Counsel is not obligated to defend the Agency or the Beneficial Owners regarding the tax-exempt status of the 2024 Series 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 the Agency legitimately disagrees, may not be practicable. Any action of the IRS, including but not limited to selection of the 2024 Series 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 2024 Series A Bonds, and may cause the Agency or the Beneficial Owners to incur significant expense.

Payments on the 2024 Series A 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 Beneficial Owner of 2024 Series A Bonds may be subject to backup withholding with respect to "reportable payments," which include interest paid on the 2024 Series A Bonds and the gross proceeds of a sale, exchange, redemption, retirement or other disposition of the 2024 Series A 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 Beneficial Owner's federal income tax liability, if any, *provided*, *however*, that the required information is timely furnished to the IRS. Certain Beneficial Owners (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.

2024 Series B Bonds

Interest on 2024 Series B Bonds is not excluded from gross income for federal income tax purposes under Section 103 of the Code. Bond Counsel is of the opinion that interest on the 2024 Series B Bonds is exempt from individual income taxes imposed by the State of Utah. Bond 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 2024 Series B Bonds. A complete copy of the proposed form of opinion of Bond Counsel is set forth as APPENDIX E hereto.

UNDERWRITING

The Underwriters have jointly and severally agreed, subject to certain conditions, to purchase the 2024 Series A and B Bonds from the Agency at an aggregate underwriting discount of $421,750 from the initial public offering prices of such 2024 Series A and B Bonds as reflected in the prices or yields set forth on the inside front cover of this Official Statement (equal to approximately 0.241% of the principal amount of the 2024 Series A and B Bonds), and to make a public offering of the 2024 Series A Bonds at not higher than the prices or lower than the yields set forth on the inside front cover of this Official Statement, plus accrued interest, if any. The Underwriters will be obligated to purchase all the 2024 Series A and B Bonds if any such 2024 Series A or B Bonds are purchased. The Underwriters are Goldman Sachs & Co. LLC and RBC Capital Markets, LLC.

The 2024 Series A and B Bonds may be offered and sold to certain dealers (including underwriters and other dealers depositing such Bonds into investment trusts) at prices lower than the public offering prices or at yields greater than the public offering yields set forth on the inside front cover of this Official Statement, and such public offering prices or yields may be changed, from time to time, by the Underwriters.

The Underwriters and their respective affiliates are full service financial institutions engaged in various activities, which may include sales and trading, commercial and investment banking, advisory, investment management, investment research, principal investment, hedging, market making, brokerage and other financial and non-financial activities and services. In addition, any of the Underwriters or their affiliates may extend credit to the Agency pursuant to a credit or loan agreement. The Underwriters and their respective affiliates have provided, and may in the future provide, a variety of these services to the Agency and to persons and entities with relationships with the Agency, for which they received or will receive customary fees and expenses. Under some circumstances, the Underwriters may have certain creditor or other rights against the Agency in connection with such services.

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

MUNICIPAL ADVISOR

Stifel, Nicolaus & Company, Incorporated (the "Municipal Advisor") has been employed as independent municipal advisor to the Agency in connection with the issuance of the 2024 Series A and B Bonds. The Municipal Advisor has read and participated in the drafting of certain portions of this Official Statement, but has not audited, authenticated or otherwise verified the accuracy or completeness of the information set forth herein or in any other information made available by the Agency in connection with the offering of the 2024 Series A and B Bonds. The Municipal Advisor makes no guaranty, warranty or other representation respecting the accuracy and completeness of this Official Statement or any other matter related hereto. The Municipal Advisor's fees for services rendered with respect to the sale of the 2024 Series A and B Bonds are, in part, contingent upon the issuance and delivery of the 2024 Series A and B Bonds.

CERTAIN LEGAL MATTERS

The validity of the 2024 Series A and B Bonds and certain other legal matters are subject to the approving opinion of Orrick, Herrington & Sutcliffe LLP, New York, New York, Bond Counsel to the Agency. A complete copy of the proposed form of Bond Counsel opinion is contained in APPENDIX E hereto. Copies of such opinion will be provided to the original purchasers without charge.

Certain legal matters with respect to the Agency will be passed upon by Holland & Hart LLP, Salt Lake City, Utah, Counsel to the Agency. Certain legal matters will be passed upon for the Underwriters by their counsel, Gilmore & Bell, P.C., Salt Lake City, Utah.

The Agency has received opinions dated March 30, 1983 from counsel to each of the Power Purchasers to the effect that such Power Purchaser's Power Sales Contract and, if such Power Purchaser is a party to the Excess Power Sales Agreement, the Excess Power Sales Agreement constitute legal, valid and binding obligations of such Power Purchaser, enforceable against such Power Purchaser in accordance with their respective terms. The Agency expects to receive letters from counsel to each of the Power Purchasers confirming such opinions on the date of delivery of the 2024 Series A and B Bonds, other than confirmations of such opinions with respect to a Cooperative Purchaser with a Generation Cost Share and a Generation Entitlement Share (as such terms are defined in the Power Sales Contracts) of 0.20 percent.

The Agency has received opinions from counsel to each of the Renewal Power Purchasers to the effect that such Renewal Power Purchaser's Renewal Power Sales Contract and, if such Power Purchaser is a party to the Agreement for Sale of Renewal Excess Power, the Agreement for Sale of Renewal Excess Power constitute legal, valid and binding obligations of such Renewal Power Purchaser, enforceable against such Power Purchaser in accordance with their respective terms. Such opinions of counsel were received in January 2017 with respect to the Renewal Power Sales Contracts and May 2017 with respect to the Agreement for Sale of Renewal Excess Power. The Agency expects to receive letters from counsel to each of the Renewal Power Purchasers confirming such opinions on the date of delivery of the 2024 Series A and B Bonds, other than a confirmation of such opinion with respect to a Cooperative Purchaser with a Generation Cost Share and a Generation Entitlement Share (as such terms are defined in the Renewal Power Sales Contracts) of 0.202 percent.

INDEPENDENT AUDITORS

The financial statements of Intermountain Power Agency as of and for the fiscal years ended June 30, 2024 and 2023, included in APPENDIX B to this Official Statement, have been audited by Deloitte & Touche LLP, an independent auditor, as stated in their report appearing therein.

MISCELLANEOUS

During the initial offering period of the 2024 Series A and B Bonds, copies of the forms of the Power Sales Contracts, the Renewal Power Sales Contracts, the Excess Power Sales Agreement, the Agreement for Sale of Renewal Excess Power, the Resolution, the Construction Management and Operating Agreement, the STS Agreement (as defined in the 2023 Annual Filing), the Transmission Service Contracts (as defined in the 2023 Annual Filing) and the Hydrogen Billing Procedure may be obtained from the Agency upon written request. Requests should be addressed to Intermountain Power Agency, 10653 South River Front Parkway, Suite 120, South Jordan, Utah 84095, Attention: Cameron R. Cowan, General Manager.

INTERMOUNTAIN POWER AGENCY

By: /s/ NICK TATTON
Chair

By: /s/ CAMERON R. COWAN
General Manager

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APPENDIX A

UPDATE INFORMATION

The information set forth in this Appendix A updates, modifies, supersedes and supplements portions of the 2023 Annual Filing as indicated below:

1. INTRODUCTION

The last sentence of the third paragraph under the section captioned "INTRODUCTION – The Project and the Generation Renewal Project" in the 2023 Annual Filing is replaced in its entirety by the following:

Neither the Agency nor the Operating Agent is aware of any operational or equipment problems that would materially and adversely affect future operations of the coal units through the commercial operation date of the natural gas units described below.

The last sentence under the section captioned "INTRODUCTION – STS Renewal Project" in the 2023 Annual Filing is replaced in its entirety by the following:

As of August 31, 2024, the Agency had expended approximately $588,000,000 (approximately 21%) of the $2.75 billion cost currently budgeted for the STS Renewal Project.

2. CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

The seventh bullet under the third paragraph under the section captioned "CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION" in the 2023 Annual Filing is replaced in its entirety by the following:

- substantial public sentiment against the use of fossil fuels for electric generating facilities and transition risks associated with a move to a lower carbon economy to mitigate the effects of climate change;

3. RISK FACTORS

The section captioned "RISK FACTORS – Utah Legislative Actions" in the 2023 Annual Filing is replaced in its entirety by the following:

The Utah Legislature enacted legislation in its 2024 General Session, S.B. 161, that imposes requirements on the Agency that purport to create obligations for the Agency that are inconsistent with the Agency's obligations under federal regulations and the Project's construction and operating permits issued under federal law. In a later special session, the Utah Legislature modified its prior enactment by enacting H.B. 3004 to eliminate the requirements for the Agency to act in a manner giving rise to immediate concern. The stated purpose of S.B. 161 continues to be to facilitate the operation of at least one of the Project's coal units after July 1, 2025 (the date by which the Agency has committed to cease operation of the Project's coal units permanently), and S.B. 161 still requires a state authority to study the possibility for such operation and for the Agency to provide information to facilitate such study.

Even with the enactment of H.B. 3004, the Agency cannot predict the potential impacts of S.B. 161 on the operation of the Project or the construction and operation of the Generation Renewal Project, nor the impacts on the Agency's financial condition or funds available to the Agency for repayment of the Covered Bonds. The Agency will continue to assess the impacts of the new legislation on the Agency and the Project and plans to continue to take actions that the Agency believes are most likely to result in timely repayment of the Covered Bonds.

See "ELECTRIC INDUSTRY RESTRUCTURING – Utah Electric Energy Actions – S.B. 161 & H.B. 3004" herein.

The last four sentences of the first paragraph under the section captioned "RISK FACTORS – Permits" in the 2023 Annual Filing are replaced in their entirety by the following:

Furthermore, Utah enacted S.B. 161 and H.B. 3004 during the 2024 general legislative session and a special legislative session, respectively, which require a state authority, the Decommissioned Asset Disposition Authority ("DADA"), to submit an application by December 31, 2024 for the operation of one of the Project's coal-fired units after July 1, 2025 for an indefinite period of time. The legislation provides that any such application would be evaluated under the State's existing rules based on updated "assumptions, modeling and requirements," as if the Agency had submitted the application. Although the legislation does not explicitly require the Agency to submit such an application, the Agency is assessing the scope of a permit application that would allow for operation of one of the coal units and cannot predict at this time the impact of this permitting exercise on the Project. See "ELECTRIC INDUSTRY RESTRUCTURING – Utah Electric Energy Actions – *S.B. 161* and – *H.B. 3004*" herein.

4. INDEBTEDNESS OF THE AGENCY

The first sentence of the section captioned "INDEBTEDNESS OF THE AGENCY – General" in the 2023 Annual Filing is replaced in its entirety by the following:

As of July 1, 2024, the Agency's indebtedness consisted of $1,632,650 principal amount of the Covered Bonds.

5. ELECTRIC INDUSTRY RESTRUCTURING

The penultimate sentence of the first paragraph under the section captioned "ELECTRIC INDUSTRY RESTRUCTURING – General" in the 2023 Annual Filing is replaced in its entirety by the following:

The general political climate in other states increasingly disfavors fossil fuel-fired power plants.

The second and third sentences of the first paragraph under the section captioned "ELECTRIC INDUSTRY RESTRUCTURING – Federal Electric Energy Actions – FERC Open-Access Transmission Initiatives" in the 2023 Annual Filing are replaced in their entirety by the following:

The first of these rules, Order No. 888: (i) requires all "public utilities" (the term FERC uses for utilities that are generally subject to FERC regulations under the FPA) to offer non-discriminatory, open-access transmission services to entities seeking to effect wholesale power transactions, under terms and conditions that are comparable to the services that they provide to themselves; and (ii) requires "non-public utilities" (the term FERC uses for utilities that are not generally subject to FERC regulations under the FPA including municipal utilities, such as the Agency, and consumer-owned utilities) that purchase transmission services from a public utility to provide, in turn, non-discriminatory, open-access transmission services back to such public utility under terms and conditions that are comparable to the services that they provide to themselves (the requirement described in clause (ii) above that applies to non-public utilities is referred to herein as the "Reciprocity Requirement"). The second rule, Order No. 889: (i) implements standards of conduct to ensure that utilities that offer open-access transmission services and their affiliates do not have an unfair competitive advantage in using their position as a transmission services provider to sell power; and (ii) requires those utilities to share electronically (via the internet) important information regarding the pricing and availability of transmission services.

The following is added as the new penultimate sentence of the penultimate paragraph under the section captioned "ELECTRIC INDUSTRY RESTRUCTURING – Federal Electric Energy Actions – FERC Open-Access Transmission Initiatives" in the 2023 Annual Filing:

Order No. 2023 also required all public utility transmission providers to adopt revised pro forma Large Generator Interconnection Procedures, pro forma Large Generator Interconnection Agreements, pro forma Small Generator Interconnection Procedures, and pro forma Small Generator Interconnection Agreements. On March 21, 2024, FERC issued Order No. 2023-A, modifying and clarifying the requirements in Order No. 2023.

The last paragraph under the section captioned "ELECTRIC INDUSTRY RESTRUCTURING – Federal Electric Energy Actions – FERC Open-Access Transmission Initiatives" in the 2023 Annual Filing is replaced in its entirety by the following:

On May 13, 2024, FERC issued Order No. 1920, revising the pro forma OATT to remedy deficiencies in the existing regional and local planning and cost allocation requirements. Order No. 1920 requires transmission providers to conduct long-term regional transmission planning to identify, evaluate, and select (as well as allocate the costs for) more efficient or cost-effective regional transmission solutions to address long-term transmission needs. Order No. 1920 included other reforms to improve coordination of regional transmission planning and generator interconnection processes, require consideration of certain alternative transmission technologies in regional transmission planning processes, and improve the transparency of local transmission planning processes and coordination between regional and local transmission planning processes. Requests for rehearing of Order No. 1920 are currently pending before FERC. Because FERC's electric transmission planning and cost allocation requirements apply to transmission providers that are public utilities under the FPA, the Agency does not believe that the requirements of Order No. 1920 will impact the Agency or its planning processes.

The first sentence of the third paragraph under the section captioned "ELECTRIC INDUSTRY RESTRUCTURING – Utah Electric Energy Actions" in the 2023 Annual Filing is replaced in its entirety by the following:

H.B. 374 became effective on May 1, 2024.

The first sentence of the first paragraph under the section captioned "ELECTRIC INDUSTRY RESTRUCTURING – Utah Electric Energy Actions – S.B. 161" in the 2023 Annual Filing is replaced in its entirety by the following:

S.B. 161, which became effective on May 1, 2024, previously required the Agency to submit, by July 1, 2024, a binding notice of intent to submit an application by January 1, 2025 for an amendment to its existing operating permit to allow for the operation of one of the Project's coal units after July 1, 2025. S.B. 161 still requires the Agency to grant the State an option to purchase a coal unit (the option to be exercisable for a two-year period beginning on July 2, 2025).

The following is added as the new section captioned "ELECTRIC INDUSTRY RESTRUCTURING – Utah Electric Energy Actions – H.B. 3004" immediately following the last paragraph of the section captioned "ELECTRIC INDUSTRY RESTRUCTURING – Utah Electric Energy Actions – S.B. 161" in the 2023 Annual Filing:

Consistent with prior public comments, the Utah governor called a special session of the Utah legislature for June 2024. In that special session, the Utah legislature enacted H.B. 3004 to remove the Agency's obligation to submit an application for an amendment to its existing operating permit under the CAA. The law also removed the Agency's obligation to submit a notice of intent to file such an application. H.B. 3004 also removed the direction to the Utah Legislative Management Committee to recommend action, including potential reconstitution of the Agency's board of directors, with respect to the failure of the Agency to submit such an application.

H.B. 3004 does require DADA, the state authority created under S.B. 161, to submit an application for an amendment to the Agency's air permit by December 31, 2024 or, if DADA determines that submitting the application by such date is not feasible, as soon as practicable following such date. The amendment to the permit for which DADA is to apply is to be for the operation of an IPP coal unit after December 21, 2027 (the date by which the Utah regional haze SIP contemplates that both IPP coal units will cease operations). As already provided in S.B. 161, DAQ is to assess the application submitted by DADA as if it had been submitted by the Agency.

The Agency is still assessing the impacts of H.B. 3004 on the Agency and the Project. The Agency is working to determine the appropriate course of action in response to the new law.

The following is added as the new third to last bullet under the section captioned "ELECTRIC INDUSTRY RESTRUCTURING – Utah Electric Energy Actions – Other Factors" in the 2023 Annual Filing:

- increases in the demand for electricity, particularly due to the growth of data centers and electrification, and the resulting impact on resource adequacy;

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6. ENVIRONMENTAL AND HEALTH FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY

The fourth paragraph under the section captioned "ENVIRONMENTAL AND HEALTH FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY – Air Emissions – New Source Review" in the 2023 Annual Filing is replaced in its entirety by the following:

However, Utah enacted S.B. 161 and H.B. 3004 during the 2024 general legislative session and a special legislative session, respectively, which require a new state entity—the Decommissioned Asset Disposition Authority—to submit an application by December 31, 2024 for the operation of one of the Project's coal-fired units after July 1, 2025 for an indefinite period. The legislation provides that any such application would be evaluated under the State's existing rules based on updated "assumptions, modeling and requirements." The Agency would not be the applicant or operator of the unit, but it is assessing the scope of any permit application that would allow for operation of one of the coal units and cannot predict at this time the impact of this permitting exercise on the Project. See "ELECTRIC INDUSTRY RESTRUCTURING – Utah Electric Energy Actions – *S.B. 161* and – *H.B. 3004*" herein.

The section captioned "ENVIRONMENTAL AND HEALTH FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY – Air Emissions – NOx Emissions" in the 2023 Annual Filing is replaced in its entirety by the following:

NOx Emissions. EPA also has issued regulations implementing the NOx provisions of the CAA. EPA uses nitrogen dioxide ("NO_2") as the indicator for NOx. These regulations mandate lower NOx emission limits for wall-fired boilers (such as those of the Project) and tangentially-fired boilers. According to the Operating Agent, the Project complies with the revised lower limits for NOx.

On February 9, 2010, EPA published revisions strengthening the health-based NAAQS. EPA set a new one-hour NO_2 standard (designed to protect against exposure to NOx) at the level of 100 ppb. The entire State, including Millard County, has been designated by EPA as "unclassifiable/attainment" under the NOx NAAQS.

On October 28, 2024, the U.S. District Court for the Northern District of California approved a consent decree between EPA and environmental plaintiffs including the Center for Biological Diversity, Sierra Club and the Center for Environmental Health, that would require EPA to complete a review of the primary NOx NAAQS and issue any resulting revisions of the standard by November 10, 2028.

The last sentence of the first paragraph under the section captioned "ENVIRONMENTAL AND HEALTH FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY – Air Emissions – PM10 and PM2.5 Emissions" in the 2023 Annual Filing is replaced in its entirety by the following:

States and industry parties are challenging the stricter $PM_{2.5}$ standards in the DC Circuit Court of Appeals and are currently briefing the merits of the case. The parties have completed briefing and oral argument is scheduled for December 16, 2024.

The second paragraph under the section captioned "ENVIRONMENTAL AND HEALTH FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY – Air Emissions – Ozone" in the 2023 Annual Filing is replaced in its entirety by the following:

Portions of the Uinta Basin and the Wasatch Front are designated as "Moderate Nonattainment" and "Marginal Nonattainment," but all other counties in the State, including Millard County, are designated as "Attainment/Unclassifiable" with the 2015 standards.

The last sentence of the third paragraph under the section captioned "ENVIRONMENTAL AND HEALTH FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY – Air Emissions – Ozone" in the 2023 Annual Filing is deleted in its entirety.

The last sentence of the fourth paragraph under the section captioned "ENVIRONMENTAL AND HEALTH FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY – Air Emissions – Ozone" in the 2023 Annual Filing is replaced in its entirety by the following:

On March 28, 2024, Utah and Oklahoma petitioned the U.S. Supreme Court to vacate the transfer on grounds that venue is appropriate in the 10th Circuit and the Court granted certiorari on October 21, 2024. The parties are currently briefing the case. On April 24, 2024, the D.C. Circuit ordered the case to be held in abeyance pending the Supreme Court's disposition of the petition.

The following is added as the new fifth paragraph under the section captioned "ENVIRONMENTAL AND HEALTH FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY – Air Emissions – Ozone" in the 2023 Annual Filing:

On June 27, 2024, in *Ohio v. EPA*, the U.S. Supreme Court granted a request by state petitioners to stay the implementation of EPA's FIP pending judicial review by the D.C. Circuit. On August 5, 2024, EPA issued a memorandum announcing its plan to comply with the Court's stay order by issuing an administrative stay of the entire FIP. On September 12, 2024, the D.C. Circuit ordered that the case be held in abeyance and ordered a remand of the underlying administrative record to permit EPA to resolve deficiencies in the SIP that the Supreme Court identified regarding EPA's response to public comments. On October 18, 2024, the state petitioners then petitioned the U.S. Supreme Court to review the D.C. Circuit's remand of the administrative record. The petitioners also requested that the D.C. Circuit continue to hold the case in abeyance through the disposition of their petition before the Supreme Court.

The second and third paragraphs under the section captioned "ENVIRONMENTAL AND HEALTH FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY – Air Emissions – Mercury Emissions" in the 2023 Annual Filing are replaced in their entirety by the following:

On May 7, 2024, EPA finalized new MATS regulations for coal- and oil-fired EGUs based on the risk and technology review under CAA Section 112. The new regulations strengthened the limits on non-mercury metal hazardous air pollutants from existing coal-fired power plants by reducing the emission standard for filterable particulate matter, tightening mercury emission limits for existing lignite-fired EGUs, requiring coal-fired EGUs to use continuous emission monitoring systems to ensure compliance with the filterable particulate matter emission standards, and revising startup requirements to assure better emissions performance during the startup period. State and industry parties challenged the rule in the D.C. Circuit Court of Appeals and requested a stay of the rule, which the D.C. Circuit denied on August 6, 2024. States and industry parties subsequently filed a motion requesting a stay with the U.S. Supreme Court, but the Court denied the request on October 4, 2024.

The Agency does not anticipate that the new MATS regulations will impact the Project. The particulate testing conducted by the Agency demonstrates that the Project operates below the revised limit, the Agency has never utilized the startup definition removed from the rule, and the Agency anticipates that the coal units will be shut down before the deadline to install a continuous emissions monitoring system.

The third and all subsequent paragraphs under the section captioned "ENVIRONMENTAL AND HEALTH FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY – Air Emissions – Regional Haze" in the 2023 Annual Filing are replaced in their entirety by the following:

On July 6, 2022, the Utah Air Quality Board adopted Utah's regional haze SIP for the years 2018 through 2028 ("Second Implementation Period"). The Utah SIP establishes an enforceable closure date of no later than December 31, 2027 for the Project's coal-fired units. The State rejected calls to require control upgrades for SO_2 during the interim period. Utah submitted its SIP to EPA for review and EPA determined that Utah's SIP was "complete" on August 23, 2022.

In June of 2023, Sierra Club and other environmental organizations sued EPA in the federal district court for the District of Columbia for EPA's failure to take action in a timely manner on regional haze SIPs for the Second Implementation Period submitted by 34 states. The petitioners asserted that the CAA required EPA to have taken action with respect to the SIPs within 12 months of EPA determining that the SIPs were complete. Similarly, in November of 2023, the State and PacifiCorp challenged EPA's failure to take action on Utah's SIP in Utah federal district court within the 12-month deadline. On July 12, 2024, the federal district court for the District of Columbia approved a consent decree agreed to by the environmental petitioners and EPA which requires EPA to take proposed and final actions on the SIP by specific dates. The consent decree requires EPA to take final action on Utah's SIP by November 22, 2024. Based on the consent decree, the Utah federal district court granted Utah and Pacificorp's stipulation to dismiss their challenge against EPA without prejudice on August 6, 2024.

On August 18, 2024, EPA proposed to partially approve and partially disapprove portions of the Utah SIP. EPA proposed to disapprove the portions of the SIP regarding the State's long-term strategy, reasonable progress goals, and consultation with federal land managers. In proposing to disapprove Utah's long-term strategy, EPA specifically proposed to reject exemptions from emission limitations during startup, shutdown, and malfunction events at the Project. Additionally, EPA requested comment on the potential impact of S.B. 161 and H.B. 3004, enacted during the 2024 general session and a special session of the Utah legislature, respectively, on the provision in Utah's SIP requiring retirement of the coal-fired units by December 31, 2027 as well as the requirement under the CAA Section 110(a)(2)(E) for the Utah SIP to provide necessary assurances that the State will have adequate resources and authority to implement the SIP. S.B. 161 and H.B. 3004 which require a state agency—the Decommissioned Asset Disposition Authority—to submit an application for the operation of one of the Project's coal-fired units for an indefinite period expected to continue beyond the retirement date of December 31, 2027 established under the Utah SIP. The operation of one of the coal-fired units beyond that date would conflict with the assumptions and requirements of Utah's SIP. See "ELECTRIC INDUSTRY RESTRUCTURING – Utah Electric Energy Actions – S.B. 161 & H.B. 3004" herein.

The Agency submitted comments on the proposed rule on September 18, 2024. In the comments, the Agency supported the partial approvals but strongly objected to the proposed partial disapprovals. The

Agency explained that EPA exceeded its authority by proposing to disapprove Utah's long-term strategy for regional haze which identifies necessary emission control measures, consistent with the requirements of the CAA. The Agency also argued that EPA exceeded its authority in rejecting the startup, shutdown, and malfunction exemptions applicable to the Project and explained that S.B. 161 and H.B. 3004 do not provide a basis to disapprove Utah's SIP. The Agency believes that S.B. 161 and H.B. 3004 do not trigger disapproval of the Utah SIP under CAA Section 110(a)(2)(E). While the Agency acknowledges that S.B. 161, as initially adopted, had the potential to affect its ability to cease operating the units, changes made in H.B. 3004 removed required actions that would have necessarily contravened the SIP. S.B. 161 and H.B. 3004 still require Intermountain Power and others to take actions that potentially preserve the option of operating one of the IPP coal units after December 21, 2027. However, S.B. 161 and H.B. 3004 do not explicitly require that the units remain operational beyond December 21, 2027. The Agency understands that additional regulatory and legislative action would be required to allow for operation of an IPP coal unit beyond that date.

It is not possible to evaluate the potential impact of EPA's proposed partial disapproval of the SIP on the Agency since the rule has not yet been finalized.

The second paragraph under the section captioned "ENVIRONMENTAL AND HEALTH FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY – Air Emissions – Regulation of Greenhouse Gases—Federal and California Greenhouse Gas Initiatives" in the 2023 Annual Filing is replaced in its entirety by the following:

On May 23, 2023, EPA proposed a rule that would set new standards for CO_2 emissions from new and existing power plants. The proposed rule included GHG standards and emission guidelines based on technologies carbon capture and sequestration/storage, low-GHG hydrogen co-firing, and natural gas co-firing, which can be applied directly to power plants that use fossil fuels to generate electricity. EPA proposed to conclude that these technologies represented the best systems of emission reduction that, taking into account costs, energy requirements, and other statutory factors, are adequately demonstrated for the purpose of improving the emissions performance of the covered electric generating units. On February 9, 2024, EPA announced that it would remove from the final version of the rule the elements that would have applied to existing stationary combustion turbines, a category that includes natural gas-fired power plants. Instead, EPA stated that it will commence a new rulemaking process that will apply to all natural gas-fired plants and regulate additional pollutants.

On April 26, 2024, EPA finalized the rule, which included an exemption from the new standards for existing coal-fired steam generating units that plan to permanently cease operation before January 1, 2032. The final rule also excluded the proposed elements applicable to existing stationary combustion turbines and defined "new" stationary combustion turbines as those that commenced construction after May 23, 2023. As the Project's coal-fired units are scheduled for permanent retirement in 2025 and are required under Utah's Regional Haze SIP to cease operation by December 31, 2027, and the Agency commenced construction of the new natural-gas units before May 23, 2023, the new standards in the final rule do not apply to the Project.

State and industry parties are currently challenging the final rule in the D.C. Circuit Court of Appeals. On July 19, 2024, the D.C. Circuit denied a request for a stay on the final rule. The plaintiffs petitioned the U.S. Supreme Court to stay the rule, but the Court denied the petition on October 16, 2024. Despite denying the stay request, two of the Justices stated that the applicants have shown a strong likelihood of success on the merits.

The following is added as the new fifth paragraph under the section captioned "ENVIRONMENTAL AND HEALTH FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY – Other Environmental Regulation – Waste Management" in the 2023 Annual Filing:

In 2022, EPA proposed denials of alternative closure demonstrations submitted by several facilities based in part on their alleged failure to demonstrate compliance with requirements for closure of CCR impoundments to prevent contamination of groundwater. EPA has only finalized one denial. Industry parties are currently challenging the finalized denial in the federal district court for the Southern District of Ohio, contending that EPA is improperly interpreting the CCR Rule in the context of these groundwater issues.

The second and third sentences of the eighth paragraph (after giving effect to the foregoing addition of the new fifth paragraph) under the section captioned "ENVIRONMENTAL AND HEALTH FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY – Other Environmental Regulation – Waste Management" in the 2023 Annual Filing are replaced in their entirety by the following:

Most recently, EPA finalized a rule to expand the application of the existing CCR requirements to "legacy CCR impoundments," which include inactive surface impoundments at inactive facilities, as well as surface impoundments and landfills that closed prior to the effective date of the 2015 CCR Rule. These amendments will not have any material impact on the course of action previously required under the CCR Rule.

The last sentence of the ninth paragraph (after giving effect to the foregoing addition of the new fifth paragraph) under the section captioned "ENVIRONMENTAL AND HEALTH FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY – Other Environmental Regulation – Waste Management" in the 2023 Annual Filing is replaced in its entirety by the following:

In January 2024, EPA entered into a consent agreement and final order with an operator of a CCR impoundment in New York to settle an enforcement action concerning groundwater monitoring. In October 2024, EPA also entered into agreements with operators of CCR units in Colorado, Puerto Rico, and Pennsylvania to settle enforcement actions under the CCR Rule. These actions signal that EPA may apply stricter scrutiny to the Agency's CCR closure and groundwater monitoring plans.

The last paragraph under the section captioned "ENVIRONMENTAL AND HEALTH FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY – Other Environmental Regulation – Waste Management" in the 2023 Annual Filing is replaced in its entirety by the following:

A Utah law enacted during the 2024 general session and amended during a 2024 special session requires a state agency—the Decommissioned Asset Disposition Authority—to submit an application by December 31, 2024 for the operation of one of the Project's coal-fired units after July 2025 (the month by which the Agency has committed under the CCR Rule to retire the Project's coal-fired units from service permanently). The Agency would not be the applicant or operator of the unit under this application, but it is assessing and monitoring implications of any application on CCR compliance.

7. THE AGENCY'S FINANCING PROGRAM

The last paragraph under the section captioned "THE AGENCY'S FINANCING PROGRAM – General" in the 2023 Annual Filing is replaced in its entirety by the following:

The Agency has been financing initial costs of the STS Renewal Project through Subordinated Indebtedness which the Agency expects to repay from payments-in-aid of construction to be made from the proceeds of bonds or other obligations of SCPPA issued or to be issued for such purpose. (See "– SCPPA Financing of the Southern Transmission System" below.)

8. FISCAL YEAR 2024-2025 ANNUAL BUDGET

The section captioned "FISCAL YEAR 2023-2024 ANNUAL BUDGET" in the 2023 Annual Filing is replaced in its entirety by the following:

[*See Table on Following Page; Remainder of Page Intentionally Left Blank*]

FISCAL YEAR 2024-2025 ANNUAL BUDGET

The Operating Agent has prepared, and the Coordinating Committee has approved, an operating budget for fiscal year 2024-2025, which began on July 1, 2024. A summary of the fiscal year 2024-2025 Annual Budget adopted by the Agency's Board of Directors (which incorporates such operating budget, as amended, and as such Annual Budget has been amended) is set forth below:

INTERMOUNTAIN POWER AGENCY
FISCAL YEAR 2024-2025 ANNUAL BUDGET SUMMARY
($000)

	Generation Station	Northern Trans mission System	Southern Trans-mission System	Total[1]	Hydrogen Better-ment[2]	Hydrogen Contin-gency[3]	IGS Decom-missioning Pre-Funding[4]
Minimum Cost Component:							
Net Debt Service[5, 6]	140	(13)	4,623	4,748			
Operations	36,050	2,658	14,295	53,003			
Maintenance	41,491	1,493	12,282	55,266			
Renewals and Replacements	18,025	185	5,671	23,881	7,000		54,000
Indirect Labor[7]	47,632	0	5,013	52,645			
Taxes	15,526	440	3,482	19,448			
Risk Management	4,070	77	1,026	5,173			
Administrative and General[8]	12,168	322	2,651	15,140			
Fixed Fuel	238,678	0	0	238,678		42,410	
Total Minimum Costs[1]	413,779	5,161	49,043	467,982			
Variable Cost Component	46,723	0	0	46,723			
Total Operating Budget[1]	460,501	5,161	49,043	514,705	7,000	42,410	54,000
Total Agency Annual Budget[1]	460,501	5,161	49,043	514,705	7,000	42,410	54,000

1 Row and column totals may not add due to rounding.

2 Amount billed separately to the Department, Burbank and Glendale for hydrogen-related betterments as part of the Generation Renewal Project. Approved by Coordinating Committee Resolution No. CC-2020-011 (with respect to the Operating Budget) and Agency Board of Directors Resolution No. IPA-2020-014 (with respect to the Agency's Annual Budget). Not reflected in the "Total" column.

3 Amount billed separately to the Hydrogen Purchasers pursuant to the Hydrogen Billing Procedure.

4 Amount billed separately to the Power Purchaser electing to pay its Pre-Funding Charge pursuant to the Pre-Funding Plan approved pursuant to Coordinating Committee Resolution No. CC-2020-012, Renewal Contract Coordinating Committee Resolution No. RCCC-2020-002, and Agency Board of Directors Resolution No. IPA-2020-011 (as Pre-Funding Charge and Pre-Funding Plan are defined in such resolutions).

5 Total debt service on all Agency obligations, plus ongoing financing expenses, less estimated interest earnings available to reduce power costs.

6 Excludes SCPPA debt service costs which are not part of the Agency's Annual Budget.

7 Labor costs for IPSC.

8 Excludes certain SCPPA costs which are not part of the Agency's Annual Budget.

For a description of the circumstances under which the Agency is required to adopt an amended Annual Budget, see "SECURITY AND SOURCES OF PAYMENT FOR THE BONDS – Budgeting" herein.

9. COORDINATING COMMITTEE

The entry for Murray City in the list under the section captioned "COORDINATING COMMITTEE" in the 2023 Annual Filing is replaced in its entirety by the following:

Power Purchaser(s) Represented	Representative	Voting Rights Percentage
Department of Water and Power of The City of Los Angeles	David Hanson	48.617
City of Riverside	David Garcia	7.617

10. RENEWAL CONTRACT COORDINATING COMMITTEE

The entry for Murray City in the list under the section captioned "RENEWAL CONTRACT COORDINATING COMMITTEE" in the 2023 Annual Filing is replaced in its entirety by the following:

Power Purchaser(s) Represented	Representative	Voting Rights Percentage
Department of Water and Power of The City of Los Angeles	David Hanson	71.442

11. PROJECT OPERATIONS

The first sentence of the last paragraph under the section captioned "PROJECT OPERATIONS – Interconnections to the Project" in the 2023 Annual Filing is replaced in its entirety by the following:

The Agency has eight additional active interconnection requests in various stages in the generation interconnection queue, including wind and solar energy and battery energy storage with maximum output of 4,175 MW.

The first paragraph under the section captioned "PROJECT OPERATIONS – Fuel Supply" in the 2023 Annual Filing is replaced in its entirety by the following:

During fiscal year 2023-2024, Unit 1 operated at a plant capacity factor of 31.58% and Unit 2 operated at a plant capacity factor of 20.87%. Coal consumption during that fiscal year was approximately 2.031 million tons.

The second sentence of the penultimate paragraph under the section captioned "PROJECT OPERATIONS – Fuel Supply" in the 2023 Annual Filing is deleted in its entirety.

The penultimate sentence of the last paragraph under the section captioned "PROJECT OPERATIONS – Fuel Supply" in the 2023 Annual Filing is replaced in its entirety by the following:

Also by October 2024, the Agency had executed fourteen North American Energy Standards Board ("NAESB") base contracts with gas suppliers.

The last sentence of the penultimate paragraph under the section captioned "PROJECT OPERATIONS – Water Supply" in the 2023 Annual Filing is replaced in its entirety by the following:

The Agency projects that annual water usage for hydrogen fuel production could increase by a maximum of approximately 2,500 acre-feet (assuming that all energy at the Project is generated using 100% hydrogen fuel).

12. LITIGATION

The last two paragraphs under the section captioned "LITIGATION – Appeals of Fees in Lieu of Property Taxes" in the 2023 Annual Filing are replaced in their entirety by the following:

In June of 2024, the Agency, the Counties and the State entered into a settlement agreement resolving all of the Agency's pending appeals with respect to Taxable Tangible Property (for the years 2014 through 2022). The Agency does not expect the terms of the settlement to have a material impact on the Agency's financial condition.

13. APPENDIX B

The rows under the heading "CALIFORNIA PURCHASERS" in the table on Appendix B ("RENEWAL POWER PURCHASERS' COST AND ENTITLEMENT SHARES") to the 2023 Annual Filing is replaced in its entirety by the following (other than the column headings set forth in bold below which are included herein for ease of reference only):

	Generation Cost Share and Entitlement Share	**Northern Transmission Cost Share and Entitlement Share**	**Southern Transmission Cost Share and Entitlement Share**
CALIFORNIA PURCHASERS			
Los Angeles Department of Water and Power	71.442%	.000%	90.500%
City of Burbank	3.334	.000	4.222
City of Glendale	4.167	.000	5.278
Total—3 California Purchasers	78.943%	.000%	100.000%

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APPENDIX B

INTERMOUNTAIN POWER AGENCY

Financial Statements for the Years Ended June 30, 2024 and 2023 and Independent Auditor's Report

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Intermountain Power Agency

Financial Statements as of and for the Years Ended June 30, 2024 and 2023, Supplemental Schedule for the Years Ended June 30, 2023 and 2024, and Independent Auditor's Report

INTERMOUNTAIN POWER AGENCY

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INDEPENDENT AUDITOR'S REPORT

To the Board of Directors of
Intermountain Power Agency:

Opinion

We have audited the financial statements of Intermountain Power Agency (IPA), which comprise the statements of net position as of June 30, 2024 and 2023, and the related statements of revenues, expenses, and changes in net position, and cash flows for the years then ended, and the related notes to the financial statements (collectively referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of IPA as of June 30, 2024 and 2023, and the changes in its net position and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

Basis for Opinion

We conducted our audits in accordance with auditing standards generally accepted in the United States of America (GAAS). Our responsibilities under those standards are further described in the Auditor's Responsibilities for the Audit of the Financial Statements section of our report. We are required to be independent of IPA 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 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 IPA'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.

Auditor's 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 auditor's 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 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 financial statements.

In performing an audit in accordance with GAAS, 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 IPA'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 IPA'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 management's discussion and analysis listed in the foregoing table of contents be presented to supplement the financial statements. Such information is the responsibility of management and, although not a part of the financial statements, is required by the Governmental Accounting Standards Board who considers it to be an essential part of financial reporting for placing the financial statements in an appropriate operational, economic, or historical context. We have applied certain limited procedures to the required supplementary information in accordance with GAAS, 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 financial statements, and other knowledge we obtained during our audit of the 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.

Supplementary Information

Our audit was conducted for the purpose of forming an opinion on the financial statements as a whole. The Supplemental Schedule of Changes in Funds Established by the IPA Revenue Bond Resolution for the Years Ended June 30, 2023 and 2024 listed in the foregoing table of contents is presented for purposes of additional analysis and is not a required part of the financial statements. Such information is the responsibility of management and was derived from and relates directly to the underlying accounting and other records used to prepare the financial statements. The information has been subjected to the auditing procedures applied in the audit of the financial statements and certain additional procedures, including comparing and reconciling such information directly to the underlying accounting and other records used to prepare the financial statements or to the financial statements themselves, and other additional procedures in accordance with GAAS. In our opinion, the information is fairly stated, in all material respects, in relation to the financial statements as a whole.

Deloitte + Touche LLP

September 27, 2024

Intermountain Power Agency

Management's Discussion and Analysis (Unaudited)

The Intermountain Power Agency (IPA) is a political subdivision of the State of Utah formed by 23 Utah municipalities pursuant to the provisions of the Utah Interlocal Co-operation Act. IPA owns, finances, operates, and maintains a two-unit, coal-fired, steam-electric generating plant and switchyard located in Millard County, Utah and transmission systems through portions of Utah, Nevada and California (the "Project"). IPA has irrevocably sold the entire capacity of the Project pursuant to Power Sales Contracts, as amended (the "Contracts"), to 35 utilities (the "Purchasers"). The Purchasers are unconditionally obligated to pay all costs of operation, maintenance and debt service, whether or not the Project or any part thereof is operating or operable, or its output is suspended, interrupted, interfered with, reduced, or terminated.

IPA's financial statements are prepared in accordance with accounting principles generally accepted in the United States of America (U.S. GAAP) and consist of statements of net position, statements of revenues, expenses, and changes in net position, statements of cash flows, and the related notes to the financial statements. The statements of net position report IPA's assets, deferred outflows of resources, liabilities, and deferred inflows of resources as of the end of the fiscal year. Investments are stated at fair value. No net position is reported in the statements of net position because IPA is completely debt financed and the Contracts contain no provision for profit. The Contracts govern how and when Project costs become billable to the Purchasers. Net costs billed to participants not yet expensed in accordance with U.S. GAAP or expenses recognized but not currently billable under the Contracts are recorded as net costs billed to participants not yet expensed (a deferred inflow) or deferred as net costs to be recovered from future billings to participants (an asset), respectively, in IPA's statements of net position. In future periods, the deferred inflow will be settled, or the asset will be recovered as the associated expenses are recognized in accordance with U.S. GAAP or when they become billable Project costs in future participant billings, respectively. At June 30, 2024 and 2023, total accumulated Project costs billed to participants exceeded accumulated U.S. GAAP expenses, resulting in a deferred inflow, net costs billed to participants not yet expensed. Over the life of the Project, aggregate U.S. GAAP expenses will equal aggregate billed Project costs. The statements of revenues, expenses, and changes in net position report the results of operations and changes in net position, and the statements of cash flows report the resulting cash flows for the fiscal year. Net costs billed to participants not yet expensed, as reported in the statements of revenues, expenses, and changes in net position, reflects the extent to which billable Project costs are greater than U.S. GAAP expenses during the fiscal year. The following table summarizes the financial condition and operations of IPA for the years ended June 30, 2024, 2023 and 2022 (in thousands):

Assets:	**2024**	**2023**	**2022**
Utility plant, net	$ 1,713,904	$ 1,057,789	$ 744,100
Cash, cash equivalents, and investments	1,058,787	732,080	1,010,553
Other	161,081	112,164	121,549
Total assets	2,933,772	1,902,033	1,876,202
Deferred outflows of resources	58,105	94,799	125,100
Total assets and deferred outflows of resources	$ 2,991,877	$ 1,996,832	$ 2,001,302
Liabilities:			
Debt	$ 1,790,280	$ 886,362	$ 997,232
Asset retirement obligations	311,939	307,050	298,107
Other	366,190	267,491	163,171
Total liabilities	2,468,409	1,460,903	1,458,510
Deferred inflows of resources:			
Net costs billed to participants not yet expensed	216,211	334,440	420,599
Prefunding of decommissioning and hydrogen betterments	303,000	197,000	118,000
Other	4,257	4,489	4,193
Total liabilities and deferred inflows of resources	523,468	535,929	542,792
	$ 2,991,877	$ 1,996,832	$ 2,001,302
Revenues, Expenses, and Changes in Net Position			
Operating revenues, net	$ 304,757	$ 387,413	$ 336,927
Fuel	(144,296)	(152,651)	(133,420)
Other operating expenses	(278,338)	(309,285)	(295,584)
Operating loss	(117,877)	(74,523)	(92,077)
Non-operating income	2,220	1,757	1,805
Net interest charges	(2,572)	(13,393)	(8,185)
Net costs to be recovered from billings to participants	118,229	86,159	98,457
Change in net position	$ -	$ -	$ -

Financial Highlights:

Assets

The net increase in gross utility plant of $748 million in 2024 resulted from additions of $749 million offset by retirements of $1 million. The 2024 additions were principally for the ongoing construction associated with IPA Repowering (see discussion of Project Repowering below). The primary components of the continued Renewal construction during the year were incurred on the gas power turbines and the Intermountain and Adelanto Converter Stations. The net increase in gross utility plant of $427 million in 2023 resulted from additions of $429 million offset by retirements of $2 million. The 2023 additions were principally for the ongoing construction and engineering for the gas turbines associated with IPA Repowering, the replacement of microwave equipment, the replacement of equipment at the Intermountain Switching Yard, construction of additional groundwater remediation wells, and the rehabilitation of the process water pond in compliance with environmental requirements.

The 2024 increase in cash, cash equivalents, and investments, combined current and restricted of $327 million is primarily due to proceeds of $921 million from the issuance of the 2023 Series A (Tax-exempt) and 2023 Series B (Taxable) Power Supply Revenue Bonds for the continued construction associated with IPA Repowering which were deposited in the Construction Fund and Debt Service Fund. Also, $354 million in payments-in-aid of construction were received from Southern California Public Power Authority (SCPPA) for renewal costs associated with the Southern Transmission System (STS) and $106 million were received from certain purchasers to prefund future decommissioning and hydrogen betterments. These were offset by $1,011 million in current year renewal expenditures, a $28 million decrease in cash needed for the credit to participants compared to the prior year, and the use of a portion of working capital to build the coal reserves for summer demand. The 2023 decrease in cash, cash equivalents, and investments, combined current and restricted of $278 million is primarily due to current year renewal expenditures of $505 million. These were offset by $187 million in payments-in-aid of construction received from SCPPA for the portion of renewal costs associated with the STS, and an additional $79 million received from certain purchasers to prefund future decommissioning and hydrogen betterments.

The 2024 increase of $49 million in other assets was primarily due to $27 million increase in fuel inventory resulting from decreased plant operation, a $17 million increase in prepaid personnel service contract costs for certain employee pensions and other postretirement benefits, and a $5 million increase in interest receivable corresponding to the increase in investments. The 2023 decrease of $9 million in other assets was caused by a decrease of $9 million in fuel inventory due to limited availably in the Utah coal market during the year.

Deferred Outflows of Resources

Deferred outflows of resources primarily consist of unamortized asset retirement costs. The decrease of $37 million in 2024 was due to $41 million in normal amortization offset by $4 million of additional unamortized retirement costs (See Note 9). The decrease of $30 million in 2023 was due to $39 million in normal amortization offset by $9 million of additional unamortized retirement costs (See Note 9).

Liabilities

During 2024, $835 million of Power Supply Revenue Bonds in the 2023 A Series (Tax-exempt) and the 2023 Series B (Taxable) were issued to provide a portion of the funds required to finance certain costs of the acquisition and construction of Project Repowering. The bonds were issued at a premium of $88 million which will be amortized over the life of the bonds. The bonds will be paid over 20 years, commencing with the first principal payment on July 1, 2026. Additionally, $6 million of scheduled principal maturities of subordinated notes were paid during 2024. All subordinated notes have now been retired. Other liabilities increased by $99 million in 2024 due to a $105 million increase in accounts payable compared to the prior year associated with the escalating Renewal Project construction activity and a $21 million increase in interest payable due to the issuance of the 2023 A Series (Tax-exempt) and the 2023 Series B (Taxable) bonds during the year. These were offset by a $28 million decrease in credit to participants.

During 2023, an additional $121 million of Transitional Project Indebtedness was issued in the form of 2019 Drawdown Bonds (See Note 7) for the upgrade of the STS which brought the total of 2019 Drawdown Bonds issued to $150 million. During June 2023, payments-in-aid of construction received from SCPPA were used to fully repay the outstanding balance. This activity resulted in a net decrease in Drawdown Bonds payable of $29 million. The 2019 Drawdown Bonds were officially closed in June 2023. Additionally, $76 million of scheduled principal maturities on subordinated notes were paid during 2023. Other liabilities increased by $104 million in 2023 due to a $108 million increase in accounts payable compared to the prior year associated with the escalating Renewal Project construction activity and a $15 million increase in interest payable due to an increase in the July 1 payment for the 2022 A Series (Tax-exempt) and the 2022 Series B (Taxable) compared to the prior year. These were offset by a $19 million decrease in credit to participants.

Moody's rates IPA's bonds at Aa3, while Fitch rates them AA-. All ratings remain unchanged from the prior year.

Deferred Inflows of Resources

At June 30, 2024 and 2023, total accumulated Project costs billed to participants exceeded accumulated U.S. GAAP expenses. Accordingly, the excess of such billings is reported as a deferred inflow, net costs billed to participants not yet expensed at June 30, 2024 and 2023. The resulting changes in net costs billed to participants not yet expensed are outlined in Note 4. During 2024 and 2023, $106 million and $79 million, respectively, was collected from certain purchasers to prefund anticipated decommissioning and hydrogen expenditures. These pre-fundings are recorded as deferred inflows of resources and will be recognized as revenue as the related expenditures become billable as monthly power costs in future years.

Revenues, Expenses, and Changes in Net Position

Net operating revenues decreased $83 million in 2024 and increased by $50 million in 2023. The decrease in 2024 is primarily due to less revenue being billed to the Purchasers due to a decrease in scheduled power. Purchasers have elected to reserve available coal inventory to ensure generation availability through June 2025 when the coal units are scheduled to cease operations. The increase in 2023 is primarily due to an increase in scheduled power compared to the prior year. Warmer than average temperatures in late summer 2022 and high natural gas prices in December and January drove the increase in scheduled power.

Fuel expense decreased by $8 million in 2024 and increased by $19 million in 2023. The decrease in 2024 is primarily due to a 30% decrease in net capacity factor caused by the planned reduction in generation noted above, offset by a 24% increase in the cost per ton of fuel burned during the current fiscal year. Conversely, the increase in 2023 is primarily due to a 6% increase in net capacity factor caused by the increase in scheduled power noted above. Other operating expenses decreased by $31 million in 2024 primarily due to the decrease in net generation. Other operating expenses increased by $14 million in 2023 primarily due to the increase in scheduled power during late summer 2022 and December and January noted above.

Net interest charges decreased by $11 million in 2024 and increased by $5 million in 2023. The 2024 decrease is due to a $42 million increase in retained earnings due to higher investment balances and a $10 increase in bond premium amortization offset by a $42 million increase in bond interest expense associated with the issuance of the 2023 Series A and 2023 Series B Bonds. The 2023 increase was due to the interest associated with the issuance of the 2022 Series A and 2022 Series B Bonds. Other non-operating income did not change significantly in 2024 or 2023. Changes in net position are zero because IPA is completely debt financed and the Contracts contain no provision for profit.

Electric Industry Legislation and Regulation

California has enacted legislation prohibiting its municipally owned electric utilities from entering into new long-term financial commitments for base load generation that do not meet certain greenhouse gases emissions performance standards. During August 2018, the California legislature passed legislation stating California policy that eligible renewable energy resources and zero-carbon resources supply 100% of retail sales of electricity to California end-use customers by December 31, 2045. These and other environmental regulation issues are discussed in Note 13 to the financial statements.

Utah Legislation

During its 2023 and 2024 sessions, HB425 and SB161, respectively were passed by the Utah State Legislature and subsequently signed into law. HB425 requires IPA to provide at least 180 days advance notice to the Legislative Management Committee of decommissioning or disposal of the IPP coal units or facilities essential to the generation of electricity by the IPP coal units. SB161 requires IPA to provide the

State of Utah the option to purchase for fair market value a coal unit and related assets intended for decommissioning, with the option remaining open for at least two years, beginning July 2, 2025.

Project Repowering

Over the past several years, IPA and the Purchasers have engaged in strategic activities so that the Project may continue operation in compliance with current electric industry regulation applicable to its Purchasers, beyond the expiration of the current Power Sales Contracts. IPA and the Purchasers executed the Second Amendatory Power Sales Contracts, which provide that the Project be repowered, and that IPA offer the Purchasers renewal in their generation and associated transmission entitlements through Renewal Power Sales Contracts (the "Renewal Contracts"), the term of which commences upon the termination of the current Power Sales Contracts on June 15, 2027. IPA and 32 of the Purchasers entered into Renewal Contracts, which became effective on January 16, 2017. Two renewing California Purchasers subsequently provided a notice of termination of their Renewal Contracts to IPA effective November 1, 2019. All entitlement shares abandoned by non-renewing purchasers were fully allocated among the remaining purchasers. The Renewal Contracts are currently effective but are to govern the purchase and sale of the capacity and output of the Project upon the termination of the Contracts. The Renewal Contracts provide for the Gas Repowering of the Project.

On September 24, 2018, IPA and the Purchasers approved changes to the repowering that constituted an Alternative Repowering under the Second Amendatory Power Sales Contracts. The Alternative Repowering is described to include the construction and installation of two combined-cycle natural gas fired power blocks, each block consisting of one gas turbine, a heat recovery steam generator train and a single steam turbine, with an approximate combined net generation capability of 840 MW.

On November 25, 2019, IPA and the Purchasers approved a Plan of Finance for funding renewal project activities that provided using shorter-term bridge financing in early project stages followed by long-term financing as required to fund anticipated costs to complete construction. Accordingly, on December 30, 2019, IPA entered into a bond purchase agreement with Royal Bank of Canada (RBC), by which IPA issued one subseries of Tax-Exempt Drawdown Bonds and one subseries of Taxable Drawdown Bonds, collectively called the 2019 Drawdown Series. Up to $100 million of drawdown bonds could be issued. As of May 2022, the entire $100 million of Drawdown Bonds had been issued. On May 12, 2022, IPA issued Power Supply Revenue Bonds 2022 Series A (Tax-Exempt) and 2022 Series B (Taxable) in the amount of $798 million to finance a portion of the cost of acquisition and construction of the Gas Repowering. A portion of the proceeds of the sale of the 2022 Series A and B Bonds was used to fully repay the $100 million of outstanding Drawdown Bonds.

On February 14, 2020, IPA awarded Mitsubishi Hitachi Power Systems a contract for two M501JAC power trains for the renewal project gas turbines. Initial milestone payments for turbine construction commenced in April 2020 and have continued through June 2022. The turbines will be commercially guaranteed capable of using a mix of 30% hydrogen and 70% natural gas at start-up in 2025. This mixture is expected to reduce carbon emissions by more than 75% compared to the retiring coal-fueled technology.

The costs of the hydrogen facilities are being funded by the Purchasers to the extent such elect to facilitate the development of such facilities. The costs of the hydrogen betterments are being funded, and some of the initial costs of the hydrogen production and storage capacity have been funded, by payments to a Hydrogen Betterments Fund established by and funded pursuant to resolutions adopted by the IPP Coordinating Committee, and the IPP Renewal Contract Coordinating Committee established pursuant to the Renewal Power Sales Contracts and IPA. LADWP, Burbank and Glendale are the only Purchasers that have elected to make payments to the Hydrogen Betterment Fund. On March 3, 2022, the IPP Coordinating Committee, the Renewal Contract Coordinating Committee and IPA approved a Hydrogen Billing Procedure that provides for LADWP and any other Purchaser that elects to become a Hydrogen Purchaser (as defined in the Hydrogen Billing Procedure) to pay all of the costs incurred by IPA with respect to that are not funded through the Hydrogen Betterments Fund (such costs to be paid by a Hydrogen Purchaser including fixed cost for Hydrogen Conversion and Storage Capacity and the variable costs of the hydrogen conversion and storage services). The obligations associated with the hydrogen facilities are discussed in Note 12 to the financial statements

IPA and the Coordinating Committee have also approved a capital improvement plan for the STS consisting of the replacement, renewal, and expansion of AC switchyards, reactive power equipment and associated facilities at the Adelanto Converter Station and the Intermountain Converter Station (STS Renewal Project). The cost of acquisition and construction will be funded through payments-in-aid of construction to be made by the Southern California Public Power Authority (SCPPA). On May 12, 2022, IPA and RBC amended and restated the bondholder agreements to allow IPA to issue additional subordinated indebtedness not to exceed $200,000,000 for the purpose of providing a portion of the monies necessary to pay the cost and acquisition and construction of the STS Renewal Project. During the year ended June 30, 2023, an additional $121 million of Drawdown Bonds were issued for the STS Renewal Project, which brought the total to $150 million. On May 30, 2023, IPA received payments-in-aid of construction from SCPPA for the entire outstanding balance of $150 million of Drawdown Bonds. The Drawdown Bonds were fully paid and closed on June 23, 2023. During June 2023, IPA received an additional $37 million of payments-in-aid of construction from SCPPA to cover ongoing construction costs on the STS.

On August 15, 2023, IPA issued Power Supply Revenue Bonds 2023 Series A (Tax-Exempt) and 2023 Series B (Taxable) in the amount of $835 million to finance a portion of the cost of acquisition and construction of the Gas Repowering. IPA anticipates issuing another series of bonds in late 2024 or early 2025 which will fund the completion of the construction of the Gas Repowering.

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INTERMOUNTAIN POWER AGENCY

STATEMENTS OF NET POSITION
JUNE 30, 2024 AND 2023 (IN THOUSANDS)

ASSETS	2024	2023
UTILITY PLANT:		
Electric plant in service	$ 4,519,623	$ 3,771,742
Less accumulated depreciation	(2,805,719)	(2,713,953)
Net	1,713,904	1,057,789
RESTRICTED ASSETS:		
Cash and cash equivalents	162,443	179,472
Investments	836,093	431,174
Interest receivable	6,846	1,537
Total	1,005,382	612,183
OTHER NON-CURRENT ASSETS		
Prepaid personnel services contract costs	52,007	34,685
Other	3,930	3,080
Total	55,937	37,765
Total Non-Current Assets	2,775,223	1,707,737
CURRENT ASSETS:		
Cash and cash equivalents	20,720	52,847
Investments	39,531	68,587
Interest receivable	701	396
Fuel inventories	79,019	51,640
Materials and supplies	15,068	17,130
Other	3,510	3,696
Total Current Assets	158,549	194,296
Total Assets	2,933,772	1,902,033
DEFERRED OUTFLOWS OF RESOURCES:		
Unamortized asset retirement costs	55,543	91,641
Other	2,562	3,158
Total Deferred Outflows of Resources	58,105	94,799
TOTAL ASSETS AND DEFERRRED OUTFLOWS OF RESOURCES	$ 2,991,877	$ 1,996,832

See notes to financial statements.

(Continued)

INTERMOUNTAIN POWER AGENCY

STATEMENTS OF NET POSITION
JUNE 30, 2024 AND 2023 (IN THOUSANDS)

LIABILITIES	2024	2023
LONG-TERM PORTION OF BONDS PAYABLE - Net	$ 1,790,280	$ 879,980
ADVANCES FROM SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY	10,930	10,930
OTHER NON-CURRENT LIABILITIES:		
Asset retirement obligations	311,939	307,050
Other	1,419	1,777
Total	313,358	308,827
CURRENT LIABILITIES:		
Current maturities of subordinated notes payable	-	6,382
Interest payable	40,886	19,621
Accrued credit to participants	10,063	38,555
Accounts payable and accrued liabilities	302,892	196,608
Total Current Liabilities	353,841	261,166
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 12)	-	-
Total Liabilities	2,468,409	1,460,903
DEFERRED INFLOWS OF RESOURCES		
Net costs billed to participants not yet expensed	216,211	334,440
Prefunding of decommissioning and hydrogen betterments	303,000	197,000
Other	4,257	4,489
Total Deferred Inflows of Resources	523,468	535,929
TOTAL LIABILITIES AND DEFERRRED INFLOWS OF RESOURCES	$ 2,991,877	$ 1,996,832

See notes to financial statements.

(Concluded)

INTERMOUNTAIN POWER AGENCY

STATEMENTS OF REVENUES AND EXPENSES, AND CHANGES IN NET POSITION
FOR THE YEARS ENDED JUNE 30, 2024 AND 2023 (IN THOUSANDS)

	2024	2023
OPERATING REVENUES:		
Power sales to participants	$ 314,820	$ 425,968
Less credit to participants	(10,063)	(38,555)
Net revenues	304,757	387,413
OPERATING EXPENSES:		
Fuel	144,296	152,651
Operation	86,962	87,663
Maintenance	44,850	54,283
Depreciation and amortization	133,616	153,287
Taxes and payment in lieu of taxes	12,910	14,052
Total expenses	422,634	461,936
OPERATING INCOME (LOSS)	(117,877)	(74,523)
NONOPERATING INCOME	2,220	1,757
INTEREST CHARGES:		
Interest on bonds and subordinated notes, and other debt	77,175	35,184
Amortization of bond premium (net of financing expenses)	(9,653)	419
(Earnings) on investments, net	(64,950)	(22,210)
Total interest charges	2,572	13,393
NET COSTS BILLED TO PARTICIPANTS NOT YET EXPENSED	(118,229)	(86,159)
CHANGE IN NET POSITION	$ -	$ -

See notes to financial statements.

INTERMOUNTAIN POWER AGENCY

STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED JUNE 30, 2024 AND 2023 (IN THOUSANDS)

	2024	2023
CASH FLOWS FROM OPERATING ACTIVITIES:		
Cash received from billings to participants	$ 382,265	$ 447,472
Other cash receipts	2,220	1,757
Cash paid to suppliers	(266,179)	(282,504)
Net cash provided by operating activites	118,306	166,725
CASH FLOWS FROM CAPITAL AND RELATED FINANCING ACTIVITIES:		
Proceeds from issuance of long-term debt	923,466	121,000
Defeasance and retirement of bonds	-	(150,000)
Debt issuance costs	(2,966)	(699)
Principal paid on long-term debt	(6,382)	(75,791)
Interest paid on long-term debt	(55,910)	(20,069)
Additions to electric plant in service	(1,062,697)	(528,156)
Payments in aid of construction	353,553	187,491
Net cash provided by (used in) capital and related financing activites	149,064	(466,224)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Purchases of investments	(1,394,110)	(285,183)
Proceeds from sales/maturities of investments	1,044,450	589,674
Interest earnings received on investments	33,134	13,323
Net cash (used in) provided by investing activities	(316,526)	317,814
NET (DECREASE) INCREASE IN CASH AND CASH EQUIVALENTS	(49,156)	18,315
CASH AND CASH EQUIVALENTS:		
Beginning balance	232,319	214,004
Ending balance	$ 183,163	$ 232,319

See notes to financial statements.

(Continued)

INTERMOUNTAIN POWER AGENCY

STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED JUNE 30, 2024 AND 2023 (IN THOUSANDS)

	2024	2023
RECONCILIATION OF OPERATING LOSS TO NET CASH PROVIDED BY OPERATING ACTIVITIES:		
Operating loss	$ (117,877)	$ (74,523)
Other non-operating income	2,220	1,757
Depreciation and amortization	133,616	153,287
Financing expenses, net of amortization of bond discount	(547)	(3,151)
Changes in operating assets and liabilities:		
Fuel inventories	(27,379)	8,951
Materials and supplies	2,062	1,544
Other current assets	186	(463)
Prepaid personel services contract costs	(17,322)	(270)
Other liabilities	(358)	97
Accounts payable and accrued liabilities	66,683	20,082
Accrued credit to participants	(28,492)	(18,941)
Other assets	(850)	806
Deferred outflows of resources	596	(1,746)
Deferred inflows of resources	105,768	79,295
NET CASH PROVIDED BY OPERATING ACTIVITIES:	$ 118,306	$ 166,725

SUPPLEMENTAL SCHEDULE OF NONCASH INVESTING AND FINANCING ACTIVITIES:

Accounts payable and accrued liabilities included $177,039 and $137,438 at June 30, 2024 and 2023, respectively, of accruals for additions to electric plant in service.

See notes to financial statements.

(Concluded)

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization and Purpose – Intermountain Power Agency (IPA), a separate legal entity and political subdivision of the State of Utah, was formed in 1977 by an Organization Agreement pursuant to the provisions of the Utah Interlocal Co-operation Act. IPA's membership consists of 23 municipalities which are suppliers of electric energy in the State of Utah. IPA's purpose is to own, acquire, construct, finance, operate, maintain, repair, administer, manage and control a facility to generate electricity located in Millard County, Utah and transmission systems through portions of Utah, Nevada and California (the "Project"). The operation and maintenance, along with construction of certain capital improvements of the Project are managed for IPA by the Department of Water and Power of the City of Los Angeles (LADWP) in its capacity as Operating Agent and Project Manager, respectively, pursuant to agreements. LADWP has also contracted to purchase a portion of the electric energy generated from the Project (see Note 11). Personnel at the generating plant are employed by Intermountain Power Service Corporation (IPSC), a separate legal non-governmental entity. IPSC is not a component unit of IPA. However, under a Personnel Services Contract ("PSC") between IPA and IPSC, IPA is required to pay all costs incurred by IPSC, including employee pensions and other postretirement benefits offered by IPSC to its employees. IPA's contractual rights and obligations under the PSC for IPSC's employee pensions and other postretirement benefits resulted in non-current assets of approximately $52,007,000 and $34,685,000 as of June 30, 2024 and 2023, respectively, as reported in the accompanying statements of net position. For the years ended June 30, 2024 and 2023, the accompanying statements of revenues, expenses, and changes in net position includes a benefit of approximately $17,322,000 and $270,000, respectively, within operation expense related to changes in these reported contractual amounts.

Use of Estimates in Preparing Financial Statements – The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America (U.S. GAAP) requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Basis of Accounting – IPA maintains its records substantially in accordance with the Federal Energy Regulatory Commission Uniform System of Accounts, as required by its Contracts (see Note 11), and in conformity with U.S. GAAP. IPA applies all of the pronouncements of the Governmental Accounting Standards Board (GASB).

Utility Plant – Electric plant in service is stated at cost, which represents the actual direct cost of labor, materials, and indirect costs, including interest and other overhead expenses, net of related income during the construction period. Depreciation of electric plant in service is computed using the straight-line method over the estimated useful lives of the assets which range from five to 50 years.

Payments-in-Aid of Construction – IPA and the Southern California Public Power Authority (SCPPA), which is comprised of certain California Purchasers (see Note 9), have entered into the Southern Transmission System Agreement, as amended, ("STS Agreement") whereby SCPPA has made payments-in-aid of construction accumulating to approximately $1,278,943,000 and $925,390,000 as of June 30, 2024 and 2023, respectively, to IPA for costs associated with the acquisition, construction and improvements of the Southern Transmission System of the Project (“STS”). Such payments-in-aid are recorded as reductions to utility plant. IPA has also entered into inter-connection agreements with other entities that have made additional payments-in-aid of construction accumulating to approximately $2,037,000 as of June 30, 2024 and 2023.

Cash and Cash Equivalents – IPA considers short-term investments with an original maturity of three months or less to be cash equivalents. As more fully discussed in Note 5, the IPA Bond Resolution required the establishment of certain funds and prescribes the use of monies in these funds. Accordingly, the assets held in certain of these funds are classified as restricted in the accompanying statements of net position. Such restricted amounts are considered cash equivalents for purposes of the statements of cash flows.

Investments – The IPA Bond Resolution, as amended, stipulates IPA may invest in any securities, obligations or investments that are permitted by Utah Law. Investments are held by IPA as beneficial owner in book-entry form. Management believes there were no investments held by IPA during the years ended June 30, 2024 and 2023 that were in violation of the requirements of the IPA Bond Resolution.

Investments are stated at fair value in accordance with GASB Statement No. 72, *Fair Value Measurement and Application*. Accordingly, the change in fair value of investments is recognized as an increase or decrease to investment assets in the statements of net position and as earnings on investments in the statements of revenues, expenses, and changes in net position.

Fuel Inventories, Materials and Supplies – Fuel inventories for the Project, principally coal, which have been purchased for the operation of the utility plant are stated at cost (computed on a last-in, first-out basis). The replacement cost of Project fuel inventory is approximately $54,196,000 and $25,237,000 greater than the stated last-in, first-out value at June 30, 2024 and 2023, respectively. Materials and supplies are stated at average cost, and the carrying value is written down for estimated excess and obsolete inventory.

Unamortized Bond Premium and Discount and Refunding Charge on Defeasance of Debt – Unamortized premium and discount related to the issuance of bonds and the unamortized refunding charge related to the refunding of certain bonds are deferred and amortized using the interest method over the terms of the respective bond issues. Bonds payable have been reported net of the unamortized bond premium and discount in the accompanying statements of net position. Unamortized refunding charge is reported as a deferred outflow of resources.

Net Costs Billed to Participants Not Yet Expensed – Billings to participants are designed to recover power costs as set forth by the Power Sales Contracts (see Note 10), which principally include current operating expenses, scheduled debt principal and interest, and deposits into certain funds. Pursuant to GASB Statement No. 62 related to regulated operations, net costs billed to participants not yet expensed in accordance with U.S. GAAP or expenses recognized but not currently billable under the Contracts are recorded as net costs billed to participants not yet expensed (a deferred inflow) or deferred as net costs to be recovered from future billings to participants (an asset), respectively, in the statements of net position. In future periods, the deferred inflow will be settled, or the asset will be recovered as the associated expenses are recognized in accordance with U.S. GAAP or when they become billable Project costs in future participant billings, respectively. At June 30, 2024 and 2023, total accumulated Project costs billed to participants to date exceeded accumulated U.S. GAAP expenses, resulting in a deferred inflow, net costs billed to participants not yet expensed (see Note 4). Over the life of the Power Sales Contracts, aggregate U.S. GAAP expenses will equal aggregate billable power costs.

California has enacted legislation prohibiting its municipally owned electric utilities from entering into new long-term financial commitments for base-load generation that do not meet certain greenhouse gases emissions performance standards. During August 2018, the California Legislature passed legislation stating California policy that eligible renewable energy resources and zero-carbon resources supply 100% of retail sales of electricity to California end-use customers by December 31, 2045. The Environmental Protection Agency (EPA) has also proposed regulation of certain greenhouse gases emissions. Future federal and state legislative and regulatory action may also result from the increasing national and international attention to climate change. Legislative and regulatory actions, both nationally and in California, have had and may yet have significant (yet hard to quantify) effects on IPA and the Purchasers (see Note 10). If these effects, which are not currently determinable, were to cause the Purchasers to be unable to meet their future power sales contract payment obligations, IPA may then be required to remove assets and liabilities recognized pursuant to IPA's regulated operations from the statement of net position when the related application criteria is no longer met unless those costs continue to be recoverable through a separate regulatory billing. As of June 30, 2024, costs deferred are probable of recovery through future billings.

Long-Lived Assets **–** IPA evaluates the carrying value of long-lived assets based upon an evaluation of indicators of impairment including evidence of physical damage, enactment or approval of laws and regulations, technological developments, changes in the manner or expected duration of use of a long-lived asset, and changes in demand. A long-lived asset that is potentially impaired is then tested to determine whether the magnitude of the decline in service utility is significant and unexpected. Measurement of the amount of impairment, if any, is based upon a restoration cost approach, service units approach, or deflated depreciated replacement cost approach, or the difference between carrying value and fair value.

Pension and Other Postretirement Obligations **–** IPA sponsors a defined benefit pension plan and a postretirement medical plan that are accounted for pursuant to GASB Statement No. 68, *Accounting and Financial Reporting for Pensions—an amendment of GASB Statement No. 27,* and GASB Statement No. 75*, Accounting and Financial Reporting by Employers for Postemployment Benefits Other Than Pensions*, respectively. No disclosures related to these plans are presented herein because amounts are not significant to the financial statements.

Asset Retirement Obligations **–** IPA records asset retirement obligations when the liability associated with the retirement of its tangible long-lived assets is both incurred and reasonably estimable. The determination of when the liability is incurred is based on the occurrence of external laws, regulations, contracts, or court judgments, together with the occurrence of an internal event that obligates an entity to perform asset retirement activities. An asset retirement obligation (ARO) is measured based on the best estimate of the current value of outlays expected to be incurred, including probability weighting of potential outcomes, with a deferred outflow of resources recognized at the amount of the corresponding liability upon initial measurement. The current value of an ARO is adjusted for the effects of general inflation or deflation at least annually. All relevant factors are evaluated at least annually to determine whether the effects of one or more of the factors are expected to significantly change the estimated asset retirement outlays. The deferred outflows of resources of asset retirement costs are amortized over the estimated useful life of the tangible capital assets. See Note 9 for additional information on IPA's asset retirement obligations.

Recently Issued Accounting Pronouncements **–** In June 2022, the GASB issued Statement No. 101, *Compensated Absences*. The statement updates the recognition and measurement guidance for compensated absences. This statement is effective for financial statements for years beginning after December 15, 2023. IPA is currently evaluating the effects the adoption of this statement will have on the financial statements.

In December 2023, the GASB issued Statement No. 102, *Certain Risk Disclosures.* The statement updates disclosure criteria for risks from concentrations and constraints. This statement is effective for financial statements for years beginning after June 15, 2024. IPA is currently evaluating the effects the adoption of this statemen will have on the financial statements.

In April 2024, the GASB issued Statement No. 103, *Financial Reporting Model Improvements*. The statement updates the information and topics required to be presented in management's discussion and analysis that precedes the financial statements; and the presentation of unusual or infrequent items, operating and nonoperating revenues and expenses, major component unit information, and budgetary comparison information. This statement is effective for financial statements for years beginning after June 15, 2025. IPA is currently evaluating the effects of the adoption of this statement will have on the financial statements.

2. UTILITY PLANT

Utility plant activity for the years ended June 30, 2024 and 2023, is as follows (in thousands):

	July 1, 2023	Increases	Decreases	June 30, 2024
Utility plant not being depreciated -				
Construction work-in-progress	$ 814,536	$ 1,096,778	$ (62)	$ 1,911,252
Land and land rights	113,823	-	-	113,823
Total	928,359	1,096,778	(62)	2,025,075
Utility plant being depreciated/amortized:				
Production	2,848,613	4,335	(674)	2,852,274
Transmission	862,874	1,077	(184)	863,767
Payments-in-aid of construction - transmission	(927,428)	(353,553)	-	(1,280,981)
General	59,324	169	(5)	59,488
Total	2,843,383	(347,972)	(863)	2,494,548
Accumulated depreciation	(3,371,145)	(119,483)	863	(3,489,765)
Accumulated amortization of payments-in-aid of construction	657,192	26,854	-	684,046
Total accumulated depreciation	(2,713,953)	(92,629)	863	(2,805,719)
Utility Plant, Net	$ 1,057,789	$ 656,177	$ (62)	$ 1,713,904

	July 1, 2022	Increases	Decreases	June 30, 2023
Utility plant not being depreciated -				
Construction work-in-progress	$ 210,554	$ 604,032	$ (50)	$ 814,536
Land and land rights	113,823	-	-	113,823
Total	324,377	604,032	(50)	928,359
Utility plant being depreciated/amortized:				
Production	2,843,742	6,194	(1,323)	2,848,613
Transmission	861,900	1,169	(195)	862,874
Payments-in-aid of construction - transmission	(739,937)	(187,491)	-	(927,428)
General	55,131	4,782	(589)	59,324
Total	3,020,836	(175,346)	(2,107)	2,843,383
Accumulated depreciation	(3,214,496)	(158,756)	2,107	(3,371,145)
Accumulated amortization of payments-in-aid of construction	613,383	43,809	-	657,192
Total accumulated depreciation	(2,601,113)	(114,947)	2,107	(2,713,953)
Utility Plant, Net	$ 744,100	$ 313,739	$ (50)	$ 1,057,789

3. CASH, CASH EQUIVALENTS AND INVESTMENTS

Cash, cash equivalents and investments consist of the following at June 30, 2024 and 2023 (in thousands:

	2024		2023	
	Fair Value	Weighted Average Remaining Maturity	Fair Value	Weighted Average Remaining Maturity
Cash and Cash Equivalents:				
Restricted:				
Short-term investments	$ 70,052	90 days or less	$ 49,734	90 days or less
Money market funds	74,100	1 day or less	104,321	1 day or less
Cash	18,291	1 day or less	25,417	1 day or less
Total Restricted	162,443		179,472	
Current:				
Money market funds	17,900	1 day or less	48,400	1 day or less
Cash	2,820	1 day or less	4,447	1 day or less
Total Current	20,720		52,847	
Total Cash and Cash Equivalents	$ 183,163		$ 232,319	
Investments:				
Restricted:				
U.S. Treasuries	$ 309,059	1.10 years	$ 198,228	1.44 years
U.S. Agencies	332,430	0.52 years	112,496	1.57 years
Commercial paper	2,391	0.84 years	1,953	0.41 years
Corporate bonds	192,213	0.87 years	118,497	1.15 years
Total Restricted	836,093		431,174	
Current:				
U.S. Treasuries	3,946	0.29 years	-	
U.S. Agencies	30,148	0.94 years	27,907	1.75 years
Commercial paper	-		15,524	0.34 years
Corporate bonds	5,437	0.55 years	25,156	0.80 years
Total Current	39,531		68,587	
Total Investments	$ 875,624		$ 499,761	

Investments consist entirely of U.S. Treasuries, U.S. Government Agencies, commercial paper and corporate bonds whose fair value is derived from inputs using observable market data to estimate current interest rates.

Interest Rate Risk – Interest rate risk is the risk that changes in interest rates will adversely affect the fair value of an investment. In accordance with its investment policy, IPA manages its exposure to interest rate risk by requiring that the remaining term to maturity of investments not exceed the date the funds will be required to meet cash obligations.

Credit Risk – Credit risk is the risk that an issuer or other counterparty to an investment will not fulfill its obligations. In accordance with its investment policy, IPA manages its exposure to credit risk by limiting its investments to securities authorized for investment of public funds under the Utah Money Management Act, which requires a rating of "A" or higher or the equivalent of "A" or higher by two nationally recognized statistical rating organizations.

Custodial Credit Risk – Cash Deposits – Custodial credit risk is the risk that, in the event of a failure of the counterparty holding the funds, IPA's deposits may not be returned. IPA does not require deposits to be fully insured and collateralized. As of June 30, 2024, approximately $21,111,000 of IPA's bank balances are uninsured and uncollateralized.

Fair Value Measurements – IPA measures and records its investments using fair value measurement guidelines established by U.S. GAAP. These guidelines recognize a three-tiered fair value hierarchy, as follows:

Level 1 – Quoted prices for identical investments in active markets;
Level 2 – Observable inputs other than quoted market prices; and,
Level 3 – Valuations derived from unobservable inputs.

At June 30, 2024 and 2023, IPA's fair value measurements and their levels within the fair value hierarchy were as follows (in thousands):

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	2024			
	Level 1	Level 2	Level 3	Total
Investments by fair value level:				
U.S. Treasuries	$ -	$ 313,005	$ -	$ 313,005
U.S. Agencies	-	362,578	-	362,578
Commercial paper	-	2,391	-	2,391
Corporate bonds	-	197,650	-	197,650
Total investments by fair value level	$ -	$ 875,624	$ -	$ 875,624

	2023			
	Level 1	Level 2	Level 3	Total
Investments by fair value level:				
U.S. Treasuries	$ -	$ 198,228	$ -	$ 198,228
U.S. Agencies	-	140,403	-	140,403
Commercial paper	-	17,477	-	17,477
Corporate bonds	-	143,653	-	143,653
Total investments by fair value level	$ -	$ 499,761	$ -	$ 499,761

4. NET COSTS BILLED TO PARTICIPANTS NOT YET EXPENSED

Net costs billed to participants not yet expensed for the years ended June 30, 2024 and 2023 and the accumulated totals as of June 30, 2024 and 2023, consisted of the following (in thousands):

	For the Years Ended June 30,		Accumulated Totals as of June 30,	
	2024	2023	2024	2023
Items in accordance with U.S. GAAP not billable to participants under the power sales contracts:				
Interest expense in excess of amounts billable	$ -	$ -	$ (452,454)	$ (452,454)
Depreciation and amortization expense	(133,616)	(153,287)	(3,257,555)	(3,123,939)
Amortization of bond discount and refunding on defeasance of bonds	13,166	3,431	(1,353,720)	(1,366,886)
Accretion of interest on zero coupon bonds	-	-	(349,408)	(349,408)
Charge on retired debt	-	-	(158,467)	(158,467)
Cumulative effect of a change in accounting principle	-	-	(18,241)	(18,241)
Accretion of asset retirement obligations	-	-	(26,965)	(26,965)
Unrealized gains on investments	2,950	(501)	(6,070)	(9,020)
Change in fair value of interest rate exchange agreements	-	-	(27,652)	(27,652)
Gain on sale of ownership interest in coal mines	-	-	4,877	4,877
Amortization of deferred fuel costs	-	-	(69,379)	(69,379)
Accrued interest earnings	-	1,249	(7,833)	(7,833)
Change in liabilities and other	15,084	(1,854)	11,353	(3,731)
Renewal project earnings	56,479	19,478	75,957	19,478
Renewal project interest expense	(79,733)	(42,801)	(122,534)	(42,801)
Amounts billed to participants under the bond resolution and the power sales contracts:				
Bond and subordinated note principal	-	76,585	5,041,757	5,041,757
Deferred fuel costs	-	-	32,228	32,228
Capital improvements	6,796	12,395	605,100	598,304
Reduction of required fund deposits	645	(854)	3,741	3,096
Cash received from sale of assets	-	-	(18,904)	(18,904)
Participant funds expended for debt reduction, refinancing and/or other financing costs (Note 10)	-	-	310,380	310,380
Net costs billed to be recovered from billings to participants	$ (118,229)	$ (86,159)	$ 216,211	$ 334,440

5. BONDS PAYABLE

To finance the construction of the Project, IPA sold Revenue Bonds (the "Senior Bonds") pursuant to IPA's Amended and Restated Power Supply Revenue Bond Resolution adopted September 28, 1978, as amended and supplemented (the "Bond Resolution"). As of June 30, 2024 and 2023, for the Senior Bonds the principal amount consisted of the following (in thousands):

Series	Bonds Dated	Final Maturity on July 1	2024	2023
Senior Bonds				
2022 A	5/12/2022	2045	$ 732,755	$ 732,755
2022 B	5/12/2022	2045	64,850	64,850
2023 A	8/15/2023	2045	767,650	-
2023 B	8/15/2023	2045	67,395	-
Total Bonds payable			1,632,650	797,605
Unamortized bond premium			157,630	82,375
Long-term portion of Bonds payable - net			$ 1,790,280	$ 879,980

Interest rates on the Bonds payable outstanding at June 30, 2024 and 2023 range from 3.5% to 5.6%.

	2024	2023
Beginning balance	$ 797,605	$ 797,605
Additions - Revenue bonds issued	835,045	-
Ending balance	$ 1,632,650	$ 797,605

The principal amounts of future maturities, sinking fund requirements and interest to be paid for the Bond outstanding as of June 30, 2024 are as follows (in thousands):

	Principal	Interest
Years ending June 30:		
2025	$ -	$ 81,773
2026	-	81,773
2027	49,615	80,548
2028	52,060	78,037
2029	54,630	75,399
2030 - 2034	316,560	332,513
2035 - 2039	402,825	244,191
2040 - 2044	513,290	130,546
2045 - 2046	243,670	12,717
Total	$ 1,632,650	$ 1,117,497

Funds Established by the Bond Resolution – The Bond Resolution requires that certain funds be established to account for IPA's receipts and disbursements and stipulates the use of monies, investments held in such funds and balances that are to be maintained in certain of the funds. Balances in the other funds are determined by resolution of the IPA Board of Directors. Except as identified below, a summary of funds established by the Bond Resolution and the aggregate amount of assets held in these funds, including accrued interest receivable as of June 30, 2024 and 2023, is as follows (in thousands):

	2024	2023
Restricted assets:		
Debt Service Fund:		
Debt Service Account	$ 130,229	$ 99,405
Debt Service Reserve Account	134,533	61,737
Subordinated Indebtedness Fund:		
Debt Service Account	-	6,382
Construction Fund:		
Tax Exempt Account	355,715	217,310
Taxable Account	61,246	9,821
STS Account (1)	34,604	33,885
Decommissiong Fund (2)	140,635	80,543
STS Decommissiong Fund (2)	26,937	-
Hydrogen Fund (3)	54,292	68,221
Hydrogen Reserve (3)	62,691	30,379
Self-Insurance Fund	4,500	4,500
Total restricted assets	1,005,382	612,183
Revenue Fund (Note 11)	60,952	121,830
Total	$ 1,066,334	$ 734,013

(1) Funded by SCPPA payments-in-aid of construction

(2) Established by supplemental resolution and not subject to the pledge in favor of bondholders

(3) Established by resolution of the IPA Board of Directors and not subject to the pledge in favor of bondholders

The reconciliation of the current assets as reported in the accompanying statements of net position to the Revenue Fund at June 30, 2024 and 2023, is as follows (in thousands):

	2024	2023
Current assets reported in statements of net position:		
Cash and cash equivalents	$ 20,720	$ 52,847
Investments	39,531	68,587
Interest receivable	701	396
Revenue Fund	$ 60,952	$ 121,830

Covenants – The Bond Resolution has imposed certain covenants upon IPA which, among others, include a promise to establish rates sufficient to pay the bondholders scheduled interest and principal payments and to make such payments on a timely basis, keep proper books of record and account, and comply with certain financial reporting and auditing requirements. IPA believes that it is in compliance with all covenants as of June 30, 2024.

Defeasance of Debt – No bonds were defeased during the years ended June 30, 2024 and 2023.

6. SUBORDINATED NOTES PAYABLE

IPA and the California Purchasers (see Note 10) have entered into the Intermountain Power Project Prepayment Agreement ("Prepayment Agreement"). Pursuant to the Prepayment Agreement, a California Purchaser, upon providing IPA sufficient funds, can direct IPA to defease certain IPA outstanding Bonds. In consideration for IPA's use of the California Purchaser's funds to defease such outstanding Bonds, IPA issues to the California Purchaser a subordinated note or notes payable. Such subordinated notes payable are not subject to early redemption by IPA and are not transferable by the holder, but otherwise carry terms substantially equivalent to the defeased Bonds (subject to certain adjustments, some of which can result in negative interest) and are junior and subordinate to Bonds payable and commercial paper notes. As of June 30, 2024 and 2023, the principal amount of interest bearing subordinated notes payable consisted of the following (in thousands):

Note Holder	Issue Date	Final Maturity on July 1	2024	2023
LADWP	3/2/2000	2023	$ -	$ 6,308
City of Pasadena	1/29/2009	2023	-	74
Total subordinated notes payable			-	6,382
Current maturities of subordinated notes payable			-	(6,382)
Long-term portion of subordinated notes payable			$ -	$ -

The changes in the par value of subordinated notes payable for the years ended June 30, 2024 and 2023, are as follows (in thousands):

	2024	2023
Beginning balance	$ 6,382	$ 82,173
Deductions - principal maturities	(6,382)	(75,791)
Ending balance	$ -	$ 6,382

As of June 30, 2024, there were no future maturities or interest payments outstanding on subordinated notes payable.

7. TRANSITION PROJECT INDEBTEDNESS

On November 25, 2019, IPA and the Purchasers approved a Plan of Finance for funding renewal project activities that anticipates using shorter-term bridge financing in early project stages followed by long-term financing as required to fund anticipated costs to complete construction. On December

27, 2019, IPA amended its subordinated indebtedness resolution to allow IPA to issue subordinated indebtedness not to exceed $100,000,000 for the purpose of providing a portion of the monies necessary to pay the Cost of Acquisition and Construction of the Gas Repowering (as defined in the Power Sales Contracts). These subordinated bonds are designated by the title "Subordinated Power Supply Revenue Bonds, 2019 Drawdown Series" (the "Drawdown Bonds") and deemed to constitute Transition Project Indebtedness as defined by the Power Sales Contracts. The Drawdown Bonds were issued by Royal Bank of Canada (RBC) on December 30, 2019, in two subseries, designated as Tax-Exempt and Taxable. The Drawdown Bonds issued and outstanding at June 30, 2021 were $38,000,000 and $3,500,000 and bore interest at 0.41% and 0.69% in the Tax-Exempt and Taxable subseries, respectively. During the year ended June 30, 2022, IPA issued additional Drawdown Bonds for construction activities resulting in the maximum amount of $92,000,000 and $8,000,000 being outstanding in the Tax-Exempt and Taxable subseries, respectively. On May 12, 2022, a portion of the proceeds of the sale of the 2022 Series A and B Bonds was used to fully repay the outstanding Drawdown Bonds.

On May 12, 2022, IPA and RBC amended and restated the bondholder agreements to allow IPA to issue additional subordinated indebtedness not to exceed $200,000,000 for the purpose providing a portion of the monies necessary to pay Cost and Acquisition and Construction of the Gas Repowering and the STS Renewal Project. During the year ended June 30, 2023, an additional $121,000,000 of Drawdown Bonds were issued for the STS Renewal Project, which brought the total to $150,000,000. On May 30, 2023, IPA received payments-in-aid of construction from SCPPA for the entire outstanding balance of the Drawdown Bonds. The Drawdown Bonds were closed on June 23, 2023.

8. ADVANCES FROM SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

In accordance with the STS Agreement, SCPPA has funded an allocable portion of certain of IPA's reserves. Management believes that advances from SCPPA in the accompanying financial statements meet those required under and are co-terminus with the STS Agreement.

9. ASSET RETIREMENT OBLIGATIONS

IPA's transmission facilities are generally located on land that is leased from Federal and certain state governments. Upon termination of the leases, the structures, improvements and equipment are to be removed and the land is to be restored. Because these leases are expected to be renewed indefinitely and because of the inherent value of the transmission corridors, the leases have no foreseeable termination date and, therefore, IPA has no asset retirement obligations (AROs) recorded related to the transmission facilities. IPA does have certain AROs related to other long-lived assets at or near the generation station site resulting from applicable laws and regulations. These obligations are related to the reclamation of certain rights-of-way, wastewater ponds, settling ponds, landfills and other facilities that may affect ground water quality.

On August 6, 2019, the IPA Board and Intermountain Power Project (IPP) Coordinating Committee formally approved the Retirement Plan for the decommissioning and retirement of the existing facilities that are not to be used for the generation or transmission of power pursuant to the Contracts (as defined in Note 10 below) or the Renewal Contracts (as defined in Note 10 below), which created a contractual requirement to retire certain capital assets under the Contracts and the Renewal Contracts. The costs of retiring or decommissioning are to be funded through indebtedness incurred by IPA in connection with the Gas Repowering. While IPA currently plans to take existing coal units out of service by July 1, 2025, any impact on the functionality of the units is subject to the current Utah law (see discussion on Utah legislation in Note 12 below).

As of June 30, 2024 and 2023, the current value of IPA's asset retirement obligations totaled approximately $311,939,000 and $307,050,000, respectively. The current value of AROs is estimated based on decommissioning cost studies typically performed by third-party experts. The increase in the current value of AROs of approximately $4,889,000 during the year ended June 30, 2024 is comprised of an increase of $9,212,000 due to the effects of general inflation, offset by a $4,323,000 decrease in a revised third-party cost estimate.

10. POWER SALES AND POWER PURCHASE CONTRACTS

IPA has sold the entire capacity of the Project pursuant to Power Sales Contracts, as amended (the "Contracts"), to 35 utilities consisting of six California municipalities ("California Purchasers"), 23 Utah municipalities ("Utah Municipal Purchasers") and six rural electrical cooperatives ("Cooperative Purchasers") (collectively, the "Purchasers"). The California Purchasers, Utah Municipal Purchasers and the Cooperative Purchasers have contracted to purchase approximately 79%, 14%, and 7%, respectively, of the capacity of the Project. The Contracts expire on June 15, 2027. As long as any of the Bonds are outstanding, the Contracts cannot be terminated nor amended in any manner which will impair or adversely affect the rights of the bondholders. Under the terms of the Contracts, the Purchasers are obligated to pay their proportionate share of all operation and maintenance expenses and debt service on the Bonds and any other debt incurred by IPA, whether or not the Project or any part thereof is operating or operable, or its output is suspended, interrupted, interfered with, reduced, or terminated. In accordance with the Contracts, billings in excess of monthly power costs, as defined, are credited to Purchasers taking power in any fiscal year (the "Participants"). IPA recorded credits to Participants in operating revenue of approximately $10,063,000 and $38,555,000 for the years ended June 30, 2024 and 2023, respectively. Such credits to Participants are applied in the subsequent year to reduce power billings in accordance with the Contracts.

As part of IPA's strategic planning initiatives, IPA and the Purchasers executed the Second Amendatory Power Sales Contracts which provide that the Project be repowered, and that IPA offer the Purchasers renewal in their generation and associated transmission entitlements through the Renewal Power Sales Contracts (the "Renewal Contracts"). IPA and 32 of the Purchasers entered into Renewal Contracts, which became effective on January 16, 2017. Two renewing California Purchasers subsequently provided a notice of termination of their Renewal Contracts to IPA effective November 1, 2019. The Renewal Contracts are currently effective but are to govern the purchase and sale of the capacity and output of the Project for the 50-year period commencing upon termination of the Contracts. The Renewal Contracts provide for the Gas Repowering of the Project.

On September 24, 2018, IPA and the Purchasers approved changes to the repowering that constituted an Alternative Repowering under the Contracts. The Alternative Repowering is described to include the construction and installation of two combined-cycle natural gas fired power blocks, each block consisting of one gas turbine, a heat recovery steam generator train and a single steam turbine, with an approximate combined net generation capability of 840 MW.

11. RELATED PARTY TRANSACTIONS

LADWP, as Operating Agent, performed engineering and other services for the Project totaling approximately $62,587,000 and $44,985,000 for the years ended June 30, 2024 and 2023, respectively, which has been billed to IPA and charged to operations or utility plant, as appropriate. Operating Agent unbilled costs totaling approximately $2,598,000 and $1,007,000 are included in accounts payable at June 30, 2024 and 2023, respectively.

Power sales to LADWP for the years ended June 30, 2024 and 2023, totaled approximately $193,347,000 and $273,381,000, respectively. There was no receivable for power sales from LADWP at June 30, 2024 and 2023. Power sales to the City of Anaheim for the years ended June 30, 2024 and 2023, totaled approximately $43,818,000 and $57,257,000, respectively. There was no receivable for power sales from the City of Anaheim at June 30, 2024 and 2023. No other individual purchasers are over 10% of generation entitlement.

Subordinated notes payable have been issued to LADWP (see Note 6). Interest income on these subordinated notes payable of approximately $0 and $4,052,000 has been recorded for the years ended June 30, 2024 and 2023, respectively, of which approximately $0 and $52,000 was receivable at June 30, 2024 and 2023, respectively. All subordinated notes to LADWP have been retired as of June 30, 2024.

Subordinated notes payable have been issued to the City of Pasadena (see Note 6). Interest income on these subordinated notes payable of approximately $0 and $111,000 has been recorded for the years ended June 30, 2024 and 2023, respectively, of which approximately $0 and $1,000 was receivable at June 30, 2024 and 2023, respectively. All subordinated notes to Pasadena have been retired as of June 30, 2024.

12. COMMITMENTS AND CONTINGENCIES

Coal Supply – At June 30, 2024, IPA was obligated under short and long-term take-or-pay coal supply contracts for the purchase of coal. The cost of coal is computed at a base price per ton, adjusted periodically for various price and quality adjustments and includes transportation to the plant. The contracts require minimum purchases of coal over the lives of the contracts, exclusive of events of force majeure, as follows (computed using the current price under the contracts, in thousands):

Years ending June 30:		
2025	$	177,491
Total	$	177,491

The actual cost of coal purchases under the coal supply contracts for the years ended June 30, 2024 and 2023, was approximately $164,654,000 and $136,894,000, respectively.

Natural Gas Supply – IPA is obligated under a contract with Kern River Gas Transmission to construct and operate a gas pipeline to deliver the natural gas supply through the life of the Renewal Contracts. Under the agreement, IPA has rights to access the pipeline through December 31, 2045. IPA is obligated to pay each year for these rights to access. IPA has also entered into contracts for base-load gas procurement with several counterparties. The contracts provide up to 35,000 MMBtus per day and will provide natural gas from May 2025 through June 2028. The contracts for pipeline access and natural gas supply require minimum payments as follows (in thousands):

Years ending June 30:		
2025	$	18,289
2026		73,748
2027		76,395
2028		72,434
2029		18,141
Thereafter		299,393
Total	$	558,400

Hydrogen Facilities – The costs of the hydrogen facilities are being funded by the Purchasers to the extent such elect to facilitate the development of such facilities. The hydrogen facilities refer to (i) the hydrogen betterments being made to the IPP natural gas units to reduce the cost of future upgrades to the units for the purpose of using higher proportions, up to 100%, of hydrogen to fuel the units, and (ii) the hydrogen conversion and storage capacity being developed by a third party at IPA's cost to convert renewable energy delivered by IPP purchasers into hydrogen that will be stored by the third party and then purchased by IPA for sale to such purchasers for use in the IPP natural gas units. The costs of the hydrogen betterments are being funded, and some of the initial costs of the hydrogen production and storage capacity have been funded, by payments to a Hydrogen Betterments Fund established by and funded pursuant to resolutions adopted by the IPP Coordinating Committee, the IPP Renewal Contract Coordinating Committee established pursuant to the Renewal Power Sales Contracts and IPA. LADWP, Burbank and Glendale are the only Purchasers that have elected to make payments to the Hydrogen Betterment Fund. IPA bills those purchasers for such payments on a monthly basis. In addition, on March 3, 2022, the IPP Coordinating Committee, the Renewal Contract Coordinating Committee and IPA approved a Hydrogen Billing Procedure that provides for LADWP and any other Purchaser that elects to become a Hydrogen Purchaser (as defined in the Hydrogen Billing Procedure) to pay all of the costs incurred by IPA with respect to hydrogen that are not funded through the Hydrogen Betterments Fund (such costs to be paid by a Hydrogen Purchaser including fixed cost for Hydrogen Conversion and Storage Capacity and the variable costs of the hydrogen conversion and storage services). The costs for the Hydrogen Conversion and Storage Capacity and the variable costs for the use of such are estimated to be approximately $3,300,000,000 during the term of the contracts providing for such capacity and services, which is expected to be approximately 30 years. The costs addressed under the Hydrogen Billing Procedure represent costs that are not included in Monthly Power Costs (as defined in the Power Sales Contracts). The Hydrogen Billing Procedure provides for a reserve of $60,000,000 to be funded at a rate of $2,500,000 per month beginning in IPA's fiscal year that commenced on July 1, 2022 (of which all $60,000,000 has been funded as of June 30, 2024). The Hydrogen Billing Procedure provides that the Hydrogen Purchasers will procure their hydrogen fuel from IPA and that IPA may condition such procurement on the execution of a fuel procurement contact between IPA and each Hydrogen Purchaser which fuel procurement contracts would require approval of the Hydrogen Purchasers' respective governing bodies.

California Greenhouse Gas Initiatives – For several years, California policy makers have sought to limit greenhouse gas emissions in California. Both the Los Angeles City Council and the State of California have adopted renewable portfolio standards, which, among other things required LADWP and the other California utilities to serve 33% and 50% of their load with renewable energy by 2020 and 2030, respectively. On September 29, 2006, California Senate Bill 1368 – An Act to Impose Greenhouse Gas Performance Standards on Locally Owned Public Utilities (SB 1368) was signed into law. SB 1368 was directed specifically at limiting greenhouse gas emissions associated with electric power consumed in California by prohibiting California electric providers from entering into long-term financial commitments for base load generation unless such generation complies with greenhouse gas emission performance standards. On September 10, 2018, California Senate Bill 100 (SB 100) was signed into law. SB 100 states California policy that eligible renewable energy resources and zero-carbon resources supply 100% of retail sales of electricity to California end-use customers by December 31, 2045. SB 100 also accelerates the existing target of 50% renewable energy by 2030, to 60% renewable energy by 2030. While these and other actions by California policy makers have the potential to impact IPA and its power purchasers, IPA does not believe that any of these initiatives will render existing Power Sales Contracts between IPA and the California Purchasers void, ineffective or unenforceable.

Other Environmental Regulation – The EPA has proposed regulation of certain greenhouse gases emissions. Future federal and state legislative and regulatory action may also result from the increasing intensity of national and international attention to climate change. Legislative and regulatory actions, both nationally and in California, have had and may yet have significant (yet hard to quantify) effects on IPA and the Purchasers.

Utah Legislation – During its 2023 and 2024 sessions, HB425 and SB161, respectively, were passed by the Utah State Legislature and subsequently signed into law. HB425 requires IPA to provide at least 180 days' advance notice to the Legislative Management Committee of decommissioning or disposal of the IPP coal units or facilities essential to the generation of electricity by the IPP coal units. SB161 requires IPA to provide the State of Utah the option to purchase for fair market value a coal unit and related assets intended for decommissioning, with the option remaining open for at least two years, beginning July 2, 2025.

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INTERMOUNTAIN POWER AGENCY

SUPPLEMENTAL SCHEDULES OF CHANGES IN FUNDS ESTABLISHED BY THE IPA REVENUE BOND RESOLUTION FOR THE YEARS ENDED JUNE 30, 2023 AND 2024 (IN THOUSANDS)

		Restricted Assets											
		Debt Service Fund		Subordinated Indebtedness Fund		Construction Fund							
	Revenue Fund	Debt Service Account	Debt Service Reserve Account	Debt Service Account	Debt Service Reserve Account	Tax Exempt Construction Account	Taxable Construction Account	STS Construction Account (1)	Decommissioning Fund (2)	Hydrogen Betterments Fund (3)	Hydrogen Reserve Fund (3)	Self-Insurance Fund	Total
BALANCE, JULY 1, 2022	$ 124,982	$ 122,856	$ 63,469	$ 4,738	$ -	$ 529,438	$ 42,498	$ 5,454	$ 52,138	$ 61,229	$ -	$ 4,500	$ 1,011,302
ADDITIONS:													
Proceeds from issuance of Bonds	-	-	-	-	-	-	-	121,000	-	-	-	-	121,000
Billings received	447,472	-	-	-	-	-	-	-	-	-	-	-	447,472
Other revenues	1,757	-	-	-	-	-	-	-	-	-	-	-	1,757
Investment earnings (loss)	3,529	1,441	(343)	-	-	11,246	907	1,514	1,405	2,203	379	(71)	22,210
Payments-in-aid of construction	-	-	-	-	-	-	-	187,491	-	-	-	-	187,491
Total	452,758	1,441	(343)	-	-	11,246	907	310,005	1,405	2,203	379	(71)	779,930
DEDUCTIONS:													
Defeasance and retirement of Bonds	-	-	-	-	-	-	-	150,000	-	-	-	-	150,000
Operating expenditures	282,504	-	-	-	-	-	-	-	-	-	-	-	282,504
Capital expenditures	23,113	-	-	-	-	356,258	-	132,165	-	16,620	-	-	528,156
Interest paid (received) on long-term debt	-	25,030	-	(4,961)	-	-	-	-	-	-	-	-	20,069
Principal paid on long-term debt	-	-	-	75,791	-	-	-	-	-	-	-	-	75,791
Debt issuance costs	-	-	-	-	-	699	-	-	-	-	-	-	699
Total	305,617	25,030	-	70,830	-	356,957	-	282,165	-	16,620	-	-	1,057,219
TRANSFERS:													
Transfer of revenues to other Funds	(72,474)	-	-	72,474	-	-	-	-	-	-	-	-	-
Other transfers	(77,819)	138	(1,389)	-	-	33,583	(33,584)	591	27,000	21,409	30,000	71	-
Total	(150,293)	138	(1,389)	72,474	-	33,583	(33,584)	591	27,000	21,409	30,000	71	-
BALANCE, JUNE 30, 2023	$ 121,830	$ 99,405	$ 61,737	$ 6,382	$ -	$ 217,310	$ 9,821	$ 33,885	$ 80,543	$ 68,221	$ 30,379	$ 4,500	$ 734,013

(1) Funded by SCPPA payments-in-aid of construction
(2) Established by supplemental resolution and not subject to the pledge in favor of bondholders
(3) Established by resolution of the IPA Board of Directors and not subject to the pledge in favor of bondholders

(Continued)

INTERMOUNTAIN POWER AGENCY

SUPPLEMENTAL SCHEDULES OF CHANGES IN FUNDS ESTABLISHED BY THE IPA REVENUE BOND RESOLUTION FOR THE YEARS ENDED JUNE 30, 2023 AND 2024 (IN THOUSANDS)

		Restricted Assets											
		Debt Service Fund		Subordinated Indebtedness Fund	Construction Fund								
	Revenue Fund	Debt Service Account	Debt Service Reserve Account	Debt Service Account	Tax Exempt Construction Account	Taxable Construction Account	STS Construction Account (1)	Decommissioning Fund (2)	STS Decommissioning Fund (2)	Hydrogen Betterments Fund (3)	Hydrogen Reserve Fund (3)	Self-Insurance Fund	Total
BALANCE, JULY 1, 2023	$ 121,830	$ 99,405	$ 61,737	$ 6,382	$ 217,310	$ 9,821	$ 33,885	$ 80,543	$ -	$ 68,221	$ 30,379	$ 4,500	$ 734,013
ADDITIONS:													
Proceeds from issuance of Bonds	-	79,664	67,642	-	721,026	55,134	-	-		-	-	-	923,466
Billings received	382,265	-	-	-	-	-	-	-		-	-	-	382,265
Other revenues	2,220	-	-	-	-	-	-	-		-	-	-	2,220
Investment earnings (loss)	4,504	6,535	5,154	-	30,067	2,753	1,949	6,101	1,866	3,554	2,312	155	64,950
Payments-in-aid of construction	-	-	-	-	-	-	353,553	-		-	-	-	353,553
Total	388,989	86,199	72,796	-	751,093	57,887	355,502	6,101	1,866	3,554	2,312	155	1,726,454
DEDUCTIONS:													
Operating expenditures	266,179	-	-	-	-	-	-	-		-	-	-	266,179
Capital expenditures	51,797	-	-	-	616,184	-	355,224	9		39,483	-	-	1,062,697
Interest paid (received) on long-term debt	588	55,375	-	(53)	-	-	-	-		-	-	-	55,910
Principal paid on long-term debt	-	-	-	6,382	-	-	-	-		-	-	-	6,382
Debt issuance costs	-	-	-	-	2,804	162	-	-		-	-	-	2,966
Total	318,564	55,375	-	6,329	618,988	162	355,224	9	-	39,483	-	-	1,394,134
TRANSFERS:													
Transfer of revenues to other Funds	53	-	-	(53)	-	-	-	-		-	-	-	-
Other transfers	(131,356)	-	-	-	6,300	(6,300)	441	54,000	25,071	22,000	30,000	(155)	-
Total	(131,303)			(53)	6,300	(6,300)	441	54,000	25,071	22,000	30,000	(155)	-
BALANCE, JUNE 30, 2024	$ 60,952	$ 130,229	$ 134,533	$ -	$ 355,715	$ 61,246	$ 34,604	$ 140,635	$ 26,937	$ 54,292	$ 62,691	$ 4,500	$ 1,066,334

(1) Funded by SCPPA payments-in-aid of construction
(2) Established by supplemental resolution and not subject to the pledge in favor of bondholders
(3) Established by resolution of the IPA Board of Directors and not subject to the pledge in favor of bondholders

(Concluded)

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APPENDIX C

DEPARTMENT OF WATER AND POWER
OF THE CITY OF LOS ANGELES

The information contained in this Appendix has been furnished to Intermountain Power Agency (the "Agency") by the Department of Water and Power of The City of Los Angeles (the "Department"). This Appendix presents dated information and neither the Agency nor the Department makes any representations regarding the accuracy of the information subsequent to the specified dates. Except as expressly provided, capitalized terms have the meanings set forth in the document to which this Appendix is attached.

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THE DEPARTMENTOF WATER AND POWER OF THE CITY OF LOS ANGELES

General

The Department is the largest municipal utility in the United States and is a proprietary department of the City. Control of Power System assets and funds is vested with the Board, whose actions are subject to review by the City Council. The Department is responsible for providing the electric and water requirements of its service area. The Department provides electric and water service almost entirely within the boundaries of the City. The City encompasses approximately 473 square miles and is populated by approximately 3.8 million residents.

Department operations began in the early years of the twentieth century. The first Board of Power Commissioners was established in 1902. Nine years later, the responsibilities for the provision of electricity and water within the City were given to the Los Angeles Department of Public Service (the "Department of Public Service"). The Department of Public Service was superseded in 1925 with passage of the 1925 Charter and the creation of the Department. The Department now operates under the Charter adopted in 2000. The operations and finances of the Water System are separate from those of the Power System.

Charter Provisions

Pursuant to the Charter, the Board is the governing body of the Department and the General Manager of the Department (the "General Manager") administers the affairs of the Department.

The Charter provides that all revenue from every source collected by the Department in connection with its possession, management and control of the Power System is to be deposited in the Power Revenue Fund. The Charter further provides that the Board controls the money in the Power Revenue Fund and makes provision for the issuance of Department bonds, notes and other evidences of indebtedness payable out of the Power Revenue Fund. The procedure relating to the authorization of the issuance of bonds is governed by Section 609 of the Charter.

Section 245 of the Charter provides that, with certain exceptions, actions of City commissions and boards ("Board Action"), including the Board, do not become final until five consecutive City Council meetings convened in regular session have passed or a waiver of such period is granted by City Council. During those five City Council meetings (unless the waiver of such period has been granted), the City Council may, on a two-thirds vote, take up the Board Action. If the Board Action is taken up, the City Council may approve or veto the Board Action within 21 calendar days of taking up the Board Action. If the City Council takes no action to assert jurisdiction over the Board Action during those five meetings, the Board Action becomes final at the end of such period.

Board of Water and Power Commissioners

Under the Charter, the Board is granted the possession, management and control of the Power System. Pursuant to the Charter, the Board also has the power and duty to make and enforce all necessary rules and regulations governing the construction, maintenance, operation, connection to and use of the Power System and to acquire, construct, extend, maintain and operate all improvements, utilities, structures and facilities the Board deems necessary or convenient for purposes of the Department. The Mayor of the City appoints, and the City Council confirms the appointment of, members of the Board. The Board is traditionally selected from among prominent business, professional and civic leaders in the City. The members of the Board serve with only nominal compensation. Certain matters regarding the administration of the Department also require the approval of the City Council.

The Board is composed of five members. The current members of the Board are:

RICHARD KATZ, *President*. Mr. Katz was appointed to the Board by Mayor Karen Bass and confirmed by the City Council on March 22, 2024. Mr. Katz was elected President of the Board on March 26, 2024. Mr. Katz is a long-time public servant and state policymaker with specific expertise in the areas of water, transportation, land use, and energy. He is the owner of Richard Katz Consulting Inc., a public policy and government relations firm based in Los Angeles. Mr. Katz previously served in the California State Assembly representing the North and East San Fernando Valley for sixteen years. After leaving the State Assembly, Mr. Katz was appointed to the State Water Resources Control Board, where he served for six years, occupying the water quality seat. Mr. Katz also served as a Senior Advisor on Energy and Water issues to Governor Gray Davis. He has previously served on the governing boards of the Los Angeles County Metropolitan Transportation Authority and Metrolink. Mr. Katz holds a Bachelor of Arts degree in political science (major) and history (minor) from San Diego State University.

GEORGE MCGRAW, *Vice President*. Mr. McGraw was appointed to the Board by Mayor Karen Bass and confirmed by the City Council on June 20, 2023. Mr. McGraw was elected Vice President of the Board on March 26, 2024. Mr. McGraw serves as founder and CEO of DigDeep, the only water, sanitation and hygiene organization solely focused on the United States, developing education, research and infrastructure programs aimed at extending the human right to clean running water to every American. In this capacity, Mr. McGraw works with local government officials, policymakers and utility providers to innovate solutions to the problems of water and sanitation access in different areas of the nation. Mr. McGraw is an Ashoka Fellow, a member of the Aspen Global Leadership Network and former Social Entrepreneur in Residence at Stanford University. He holds a Master of Arts degree in International Law and the Settlement of Disputes from the United Nations University for Peace.

NURIT KATZ, *Commissioner*. Ms. Katz was appointed to the Board by then Mayor Eric Garcetti and confirmed by the City Council on December 6, 2022. She is the Chief Sustainability Officer for the University of California, Los Angeles ("UCLA"), where she has led the development of the University's first comprehensive sustainability plan and fosters collaboration across the leading public university to advance sustainability through education, research, operations, and community partnerships. For six years Ms. Katz also served as Executive Officer for Facilities Management at UCLA. She has over 15 years of teaching experience and is an Instructor for the UCLA Extension Sustainability Certificate Program. Ms. Katz also has taught for the UCLA Institute of Environment and Sustainability and prior to UCLA worked in environmental and outdoor education. She holds a Master of Business Administration degree and a master's degree in public policy from UCLA, and a Bachelor of Arts in environmental education from Humboldt State University. She is currently pursuing a PhD in ecology and evolutionary biology at UCLA and is a Trainee in the National Science Foundation Research Traineeship Innovation at the Nexus of Food, Energy, and Water Systems program.

MIA LEHRER, *Commissioner*. Ms. Lehrer was appointed to the Board by then Mayor Eric Garcetti and confirmed by the City Council on October 21, 2020. Ms. Lehrer is president and founder of Studio-MLA, a landscape architecture, urban design, and planning practice dedicated to advocacy by design with a vision to improve quality of life through landscape. She has served as an advisor to numerous public agencies, including the United States Fine Arts Commission under President Barack Obama, the Los Angeles Cultural Heritage Commission, and the Los Angeles Zoning Advisory Committee. Ms. Lehrer was a member of the team that delivered the Los Angeles River Revitalization Master Plan and the 2020 Upper Los Angeles River and Tributaries Master Plan. She also serves on the board for the Southern California Development Forum and in 2010 she was elevated to Fellow of the American Society of Landscape Architects. Ms. Lehrer holds a Bachelor of Arts degree from Tufts University and a Master of Landscape Architecture degree from the Harvard University Graduate School of Design.

WILMA J. PINDER, *Commissioner*. Ms. Pinder was appointed to the Board by Mayor Karen Bass and confirmed by the City Council on March 8, 2024. Ms. Pinder is a former Los Angeles Assistant City Attorney. She served the city as a civil litigator and trial attorney for 30 years, 20 of those years were with the Water and Power Division of the City Attorney's Office. Ms. Pinder has been active with national, state and local bar associations, serving as a Board member on several. Ms. Pinder is a Life Fellow of the American Bar Foundation ("ABF") and served on its Board for 10 years. The ABF expands knowledge and advances justice through research on law and legal institutions. She has also served on alumni boards at the University of Southern California ("USC") and UCLA. Ms. Pinder is active in the greater Los Angeles area with a number of service-oriented groups. Ms. Pinder holds a Bachelor of Arts degree in psychology from USC, a Master of Science degree in psychology from Howard University, and a Juris Doctorate from UCLA School of Law. She is also trained in community mediation and dispute resolution.

Management of the Department

The management and operation of the Department are administered under the direction of the General Manager. The management structure of the Department consists of three functional senior executive positions: Chief Operating Officer, Senior Assistant General Manager of the Power System and Chief Financial Officer. The Department's financial affairs are supervised by the Chief Financial Officer. The Power System is directed by the Senior Assistant General Manager of the Power System with an Executive Director for Construction, Maintenance and Operations, and an Executive Director for Planning, Engineering, and Technology Applications. Legal counsel is provided to the Department by the Office of the City Attorney of the City of Los Angeles.

Below are brief biographies of the Department's General Manager, Ms. Janisse Quiñones, and other members of the senior management team for the Power System:

JANISSE QUIÑONES, PE, *General Manager/Chief Executive Officer and Chief Engineer*. Ms. Quiñones was named General Manager/Chief Executive Officer and Chief Engineer of the Department on April 19, 2024 and confirmed by the City Council on May 14, 2024. She has more than 25 years of leadership experience as a senior executive in utility and engineering industries. Prior to joining the Department, Ms. Quiñones was a Senior Vice President of Electric Operations at Pacific Gas and Electric Company ("PG&E"). She also previously served as Senior Vice President of Gas Engineering for PG&E, as the Vice President of Gas Systems Engineering for National Grid, and as Vice President of Operations for Cobra Acquisitions and Director of Design, Planning, Construction & Vegetation Management as part of her nine years of work at San Diego Gas & Electric ("SDG&E"). At SDG&E, Ms. Quiñones managed the majority of the company's gas and electric distribution capital construction. She currently serves as a Commander in the U.S. Coast Guard ("USCG") Reserves assigned to USCG District 11 and as the USCG Emergency Preparedness Liaison Officer where she is responsible for managing Local, State and Federal Emergencies. Ms. Quiñones previously served full time in the USCG as an Engineering Officer. She is a Professional Engineer with a Bachelor of Science degree in mechanical engineering from University of Puerto Rico-Mayaguez, a Master of Business Administration from University of Phoenix, and a Master of International Affairs from University of California, San Diego.

ARAM BENYAMIN, *Chief Operating Officer*. Mr. Benyamin was named Chief Operating Officer of the Department in November 2022. In this role he oversees the Water System and Power System, along with other support organizations within the Department. Prior to rejoining the Department in November 2022, Mr. Benyamin was the Chief Executive Officer for Colorado Springs Utilities (a municipally-owned utility). He joined Colorado Springs Utilities in 2015 as the General Manager – Energy Supply and was named Chief Executive Officer in October 2018. Prior to joining Colorado Springs Utilities, Mr. Benyamin was the Department's Senior Assistant General Manager – Power System. Mr. Benyamin previously worked for the Department in various roles for over 30 years. He is a Professional Engineer with a Bachelor of Science degree in engineering from California State University, Los Angeles. Mr. Benyamin also has a master's degree in business administration from the University of La Verne and a master's degree in public of administration from California State University, Northridge.

JOHN A. SMITH, *Chief Administrative Officer*. Mr. Smith was named Chief Administrative Officer of the Department on July 1, 2024. In this capacity he will oversee support organizations that service both Water and Power Systems. He has 35 years of experience with the City of Los Angeles, including 24 years with the Department. Prior to his appointment as Chief Administrative Officer, Mr. Smith served as Director of Fleet and

Aviation Services since May 2023 and previously served as Director of Facilities Services from April 2022 to May 2023. He has served in various management capacities within the Department since April 2013. He is also designated the managing responsible agent for the Department's crane inspection program licensed by the State of California Department of Industrial Relations Division of Occupational Safety and Health Crane Unit. Mr. Smith holds a Bachelor of Science degree in organizational management from the University of La Verne. Additionally, he has a Master of Science degree in management, strategy and leadership from Michigan State University.

ANN M. SANTILLI, *Chief Financial Officer*. Ms. Santilli was named Chief Financial Officer of the Department in May 2019. She had served as Interim Chief Financial Officer of the Department since March 2018. Prior to her appointment as Interim Chief Financial Officer, Ms. Santilli served as Assistant Chief Financial Officer and Controller of the Department from 2012 through February 2018 and previously held the role of Interim Chief Financial Officer of the Department from October 2010 through January 2012. Prior to her first service as Interim Chief Financial Officer, Ms. Santilli served as Chief Accounting Employee and Assistant Chief Financial Officer and Controller of the Department. She assumed the post as Controller in March 2008, as Assistant Chief Financial Officer in April 2008 and as Chief Accounting Employee in July 2010. Prior to being appointed as the Controller, Ms. Santilli was the Manager of Financial Reporting since 2003. Ms. Santilli has over 36 years of accounting and auditing experience. Ms. Santilli holds a bachelor's degree in business administration from California State University, Northridge and is a certified public accountant in the State and a certified internal auditor.

DAVID HANSON, *Interim Senior Assistant General Manager of the Power System*. Mr. Hanson was named Interim Senior Assistant General Manager of the Power System on August 14, 2024. Mr. Hanson has 22 years of experience with the Department, most recently serving as the Director of Power Construction and Maintenance within the Power System. Mr. Hanson began his career at the Department in 2002 as an Electrical Mechanic, and subsequently has held a number of supervisory and leadership positions within the Department, including Electrical Mechanic Training Center Superintendent, Manager of Construction Services and Assistant Director of Power Transmission and Distribution. Prior to joining the Department, he served his country for 10 years in the United States Navy as an Electrician's Mate First Class, Sub Surface Nuclear Power and also served as a Navy recruiter.

KATHY M. FONG, *Assistant Chief Financial Officer and Controller*. Ms. Fong was named Assistant Chief Financial Officer and Controller of the Department in March 2020 after serving as the Acting Assistant Chief Financial Officer and Controller of the Department since March 2018. Ms. Fong previously served as Assistant Controller – Financial Reporting of the Department from August 2014 through February 2018 and held the role of Manager of Financial Reporting of the Department from June 2008 through July 2014. Prior to being appointed as the Manager of Financial Reporting in 2008, Ms. Fong served as the Assistant to the Manager of the Budget Office since 2002. Ms. Fong has over 34 years of accounting and budgeting experience. Ms. Fong holds a bachelor's degree in business administration with an option in accounting from California State University, Los Angeles and is a certified public accountant in the State and a certified management accountant.

PETER HUYNH, *Assistant Chief Financial Officer and Treasurer; Assistant Auditor*. Mr. Huynh was named Assistant Chief Financial Officer and Treasurer of the Department in October 2020 and Assistant Auditor of the Department in February 2021. Prior to his appointment as Assistant Chief Financial Officer and Treasurer, Mr. Huynh served as the Assistant Director of Finance and Risk Control Division of the Department since July 2006. He has over 34 years of financial management experience in debt management, risk control, financial planning, accounting, and auditing. Mr. Huynh holds a bachelor's degree in art and a certificate in accountancy from the California State University, Los Angeles. He also has a master's degree in business administration from Pepperdine University. Mr. Huynh is a certified public accountant in the State, a certified management accountant, and a chartered global management accountant.

Employees

As of May 31, 2024, the Department assigned approximately 5,313 Department employees to the Power System on a full time basis. Approximately 3,987 additional Department employees support both the Power System and the Water System on a shared basis.

The Department conducts personnel functions in accordance with the Charter-established civil service system (the "Civil Service System") applicable to most Department employees. In accordance with the Civil Service System, the Department makes appointments on the basis of merit through competitive examinations and civil service procedures. The position of General Manager and 18 other management positions are specifically exempted from the Civil Service System.

The City Council approves the wages and salaries paid to all Department employees. In accordance with State law (the Meyers-Milias-Brown Act) and a conforming City ordinance (the Employee Relations Ordinance), the Department recognizes 14 bargaining units of Department employees. Five labor or professional organizations represent these employees' bargaining units. In the bargaining process the Department and the labor or professional organizations develop memoranda of understanding which set forth wages, hours, overtime and other terms and conditions of employment.

The International Brotherhood of Electrical Workers ("IBEW") represents more than 90% of the Department's employees through ten bargaining units. The Department's ten memoranda of understanding with IBEW have a term which commenced on October 1, 2022 and which expire on September 30, 2026.

The Department's memoranda of understanding with the Management Employees Association, Load Dispatchers Association, and Association of Confidential Employees, expire on December 31, 2025. The Department's memorandum of understanding with the Service Employees International Union, Security Unit, expires on September 30, 2026. Since the advent of collective bargaining in 1974, work stoppages have been rare, occurring in 1974, 1981 and 1993.

Retirement and Other Benefits

Retirement, Retiree Medical, Disability and Death Benefit Insurance Plan. The Department has a funded contributory retirement, disability, and death benefit insurance plan covering substantially all of its employees. The Water and Power Employees' Retirement, Disability, and Death Benefit Insurance Plan is a retirement system of employee benefits and includes the Water and Power Employees' Retirement Fund (the "Retirement Plan"), which is more fully described in "Note (13) Retirement Plan" and the "Required Supplementary Information" of the Department's Power System Financial Statements.

The costs of the Retirement Plan are shared by the Power System and the Water System, with the Power System being responsible for approximately 67% of Retirement Plan costs. Since Fiscal Year 2014-15, the assumed rate of investment return on the Retirement Plan's assets has been incrementally decreased from 7.75% to 6.50%. Most recently, effective July 1, 2022, the Retirement Board lowered the assumed rate of return from 7.00% to 6.50%. A decrease in the assumed rate of return will generally contribute to an increase in the Department's required contributions to the Retirement Plan, including the Power System's share. The budgeted contributions for the Fiscal Year ending June 30, 2024 take into account this change in the discount rate. Investment return assumptions are determined through the Retirement Plan's Experience Study, which was most recently published on May 20, 2022.

As more fully described in Note 13(d), the Power System made contributions to the Retirement Plan of approximately $249 million in Fiscal Year 2022-23 (as part of a total Department contribution of approximately $369 million), and the Power System made contributions to the Retirement Plan of approximately $218 million in Fiscal Year 2021-22 (as part of a total Department contribution of approximately $325 million). For the Fiscal Year ending June 30, 2024, the Department budgeted a contribution of approximately $304 million from the

Power Revenue Fund to the Retirement Plan (as part of a total Department contribution of approximately $447 million).

The Department also has made, and will continue to make in the future, contributions to the Plan from the Water Revenue Fund.

The Department follows the provisions of Governmental Accounting Standards Board ("GASB") Statement No. 68, *Accounting and Financial Reporting for Pension – an amendment of GASB Statement No. 27* ("GASB No. 68"). GASB No. 68 requires employers with pension liabilities to disclose the net pension liability along with deferred inflows and outflows of resources related to the pension liability. As approved by the Board, a regulatory asset has also been recorded, because this liability is expected to be funded by future revenues of the Power System. For more information about how GASB No. 68 affected the financial statements of the Power System, see "Note (6) Regulatory Assets and Liabilities" and "Required Supplementary Information" of the Department's Power System Financial Statements. Specifically, see Note 6(f) for a discussion of the Power System's establishment of the regulatory asset discussed above.

According to the latest actuarial valuation and review of the Retirement Plan that was completed by The Segal Company on September 22, 2023, as of July 1, 2023, the market value of the assets in the Retirement Plan was approximately $16.4 billion, which results in an unfunded actuarial accrued liability (based on the market value of assets) of approximately $582.0 million; the actuarial value of the assets in the Retirement Plan as of such date was approximately $16.6 billion, which would result in an unfunded actuarial accrued liability (based on the actuarial value of assets) of approximately $411.5 million. As of July 1, 2023, the Retirement Plan had unrecognized investment losses of approximately $171.0 million. The Retirement Plan employs a five-year smoothing technique to value assets in order to reduce the volatility in contribution rates. The impact of this will result in "smoothed" assets that are lower or higher than the market value of the assets depending upon whether the remaining amount to be smoothed is a net gain or a net loss. If the net deferred losses for the year ended June 30, 2023 were recognized immediately in the actuarial value of assets, the aggregate required contributions to the Retirement Plan for Fiscal Year 2023-24 would increase from approximately 31.4% of total Department covered payroll to 32.6% of total Department covered payroll. Additionally, if the net deferred losses in all available Retirement Plan funds were recognized immediately in the actuarial value of assets, the funded ratio of the Retirement Plan as of June 30, 2023 would decrease from approximately 97.6% to 96.6%.

According to the actuarial valuation and review of the Retirement Plan that was completed by The Segal Company on September 23, 2022, as of July 1, 2022, the market value of the assets in the Retirement Plan was approximately $15.5 billion, which would result in an unfunded actuarial accrued liability (based on the market value of assets) of approximately $616.0 million; the actuarial value of the assets in the Retirement Plan as of such date was approximately $15.8 billion, which would result in an unfunded actuarial accrued liability (based on the actuarial value of assets) of approximately $318.0 million. As of July 1, 2022, the Retirement Plan had unrecognized investment losses of approximately $298.0 million. The Retirement Plan employs a five-year smoothing technique to value assets in order to reduce the volatility in contribution rates. The impact of this will result in "smoothed" assets that are lower or higher than the market value of the assets depending upon whether the remaining amount to be smoothed is a net gain or a net loss. If the net deferred losses for the year ended June 30, 2022 were recognized immediately in the actuarial value of assets, the aggregate required contributions to the Retirement Plan for Fiscal Year 2022-23 would increase from approximately 29.8% of total Department covered payroll to approximately 32.2% of total Department covered payroll. Additionally, if the net deferred losses in all available Retirement Plan funds were recognized immediately in the actuarial value of assets, the funded ratio of the Retirement Plan as of June 30, 2022 would decrease from approximately 98.0% to approximately 96.2%.

Contribution requirements for the Fiscal Year ending June 30, 2024 were set based on the asset values as of June 30, 2023. Significant losses in market value or the failure to achieve projected investment returns could increase unfunded pension liabilities and future pension costs. However, the Retirement Plan uses a five-year asset smoothing period of the differences between the actual market return and the expected return on the market value of assets to manage short-term volatility, as a result of which the immediate fiscal impact of any one year's negative return on the Department's contribution rates is reduced.

Effective January 1, 2014, the Board approved a new tier for new Retirement Plan members called "Tier 2." Tier 2 provides reduced retirement benefits, requires the employee to contribute a higher percentage of pay to the Retirement Plan, and ends the reciprocity agreement with the City's retirement plan. The Coalition of L.A. City Unions, whose members are not employed at the Department, has challenged the ending of the reciprocity agreement. The City is defending the challenge against the decision to end the reciprocity agreement. The outcome of the challenge to the end of the reciprocity agreement is not expected to have a material adverse impact on the Department or the Retirement Plan. According to a study of the proposed benefits of Tier 2, which was completed by The Segal Company on October 24, 2013, the estimated amount of contribution required to fund the benefit allocated to the current year of service (the "Normal Cost"), as a percentage of payroll, was 5.61% for Tier 2 (as compared to 16.35% for Tier 1), and the new tier of benefits was projected to generate a present value savings of $877 million over 30 years (based on the 7.75% assumed rate of investment return on the Retirement Plan's assets, which was in effect when Tier 2 was approved). According to the latest actuarial valuation and review of the Retirement Plan, which was completed by The Segal Company on September 22, 2023, the estimated contribution for Fiscal Year 2023-24 required to fund the benefit allocated to the Normal Cost, as a percentage of payroll, was 11.29% for Tier 2 (as compared to 21.12% for Tier 1)**.** As of the July 1, 2023 actuarial valuation report, 53% of active Department members were covered under Tier 2.

Other Postemployment Benefits ("OPEB"). The Department provides certain healthcare benefits (the "Healthcare Benefits") and death benefits to active and retired employees and their dependents. These OPEB Benefits are more particularly described in "Note (14) Other Postemployment Benefits Plans" and the "Required Supplementary Information" of the Department's Power System Financial Statements.

The costs of the Healthcare Benefits are shared by the Water System and the Power System, with the Power System historically being responsible for approximately 67% of the costs of the Healthcare Benefits. As more fully described in Note (14), the Power System paid Healthcare Benefits of approximately $75.9 million in Fiscal Year 2022-23 (as part of a total Department contribution of approximately $113.2 million), and the Power System paid Healthcare Benefits of approximately $73.7 million in Fiscal Year 2021-22 (as part of a total Department contribution of approximately $110.8 million). For the Fiscal Year ending June 30, 2024, the Department budgeted approximately $78.3 million to be paid from the Power Revenue Fund for Healthcare Benefits (with the total Department paying approximately $118.7 million).

The Department also has paid, and will continue to pay in the future, Healthcare Benefits from the Water Revenue Fund, for the Water System's Healthcare Benefits costs.

According to the latest actuarial valuation and review of the Healthcare Benefits, which was completed by The Segal Company on November 6, 2023, as of June 30, 2023, the market value of the assets of the Healthcare Benefits was approximately $3.0 billion, which would result in an overfunded actuarial accrued liability (based on the market value of assets) of approximately $345.8 million; the actuarial value of the assets in the Healthcare Benefits as of such date was approximately $3.0 billion, which would result in an overfunded actuarial accrued liability (based on the actuarial value of assets) of approximately $371.7 million. As of June 30, 2023, the Healthcare Benefits had unrecognized investment gains of approximately $25.9 million. The actuarial valuations of the Healthcare Benefits employ a smoothing policy which requires that market gains and losses be recognized in even increments over five years. As a result, the impact of this will result in "smoothed" assets that are lower or higher than the market value of the assets depending upon whether the remaining amount to be smoothed is either a net gain or a net loss. As of June 30, 2023, the ratio of the actuarial value of assets to actuarial accrued liabilities increased from 106.84% as of June 30, 2022 to 114.16% as of June 30, 2023. On a market value of assets basis, the funded ratio increased from 104.95% as of June 30, 2022 to 113.17% as of June 30, 2023. The unfunded actuarial accrued liability (on an actuarial value of assets basis) decreased from a surplus of $180.0 million as of June 30, 2022 to a surplus of $371.7 million as of June 30, 2023.

According to the actuarial valuation and review of the Healthcare Benefits, which was completed by The Segal Company on November 16, 2022, as of June 30, 2022, the market value of the assets of the Healthcare Benefits was approximately $2.8 billion, which would result in an overfunded actuarial accrued liability (based on the market value of assets) of approximately $130.3 million; the actuarial value of the assets in the Healthcare Benefits as of such date was approximately $2.8 billion, which would result in an overfunded actuarial accrued liability (based on the actuarial value of assets) of approximately $180.0 million. As of June 30, 2022, the Healthcare Benefits had unrecognized investment gains of approximately $50.0 million. The actuarial valuations of the Healthcare Benefits employ a smoothing policy which requires that market gains and losses be recognized in even increments over five years. As a result, the impact of this will result in "smoothed" assets that are lower or higher than the market value of the assets depending upon whether the remaining amount to be smoothed is either a net gain or a net loss. As of June 30, 2022, the ratio of the actuarial value of assets to actuarial accrued liabilities increased from 101.15% as of June 30, 2021 to 106.84%. On a market value of assets basis, the funded ratio decreased from 113.58% as of June 30, 2021 to 104.95% as of June 30, 2022. The unfunded actuarial accrued liability (on an actuarial value of assets basis) decreased from a surplus of $29.6 million as of June 30, 2021 to a surplus of $180.0 million as of June 30, 2022.

Contribution requirements for the Fiscal Year ending June 30, 2024 were set based on the asset values as of June 30, 2023. Significant losses in market value or the failure to achieve projected investment returns could increase unfunded pension liabilities for Healthcare Benefits and future contribution requirements. However, the Healthcare Benefits uses a five-year asset smoothing period of the differences between the actual market return and the expected return on the market value of assets to manage short-term volatility, as a result of which the immediate fiscal impact of any one year's negative return on the Department's contribution rates is reduced.

For a schedule that provides information about the Department's overall progress made in accumulating sufficient assets to pay Healthcare Benefits when due, prior to allocations to the Power System and the Water System, see the "Required Supplementary Information" of the Department's Power System Financial Statements.

Effective January 1, 2014, the Board approved a new tier for new Retirement Plan members called "Tier 2." Tier 2 provides reduced retiree healthcare benefits. According to a study of the proposed OPEB for Tier 2 employees of the Department, which was completed by The Segal Company on November 8, 2013, the estimated Normal Cost, as a percentage of payroll, was 2.63% for Tier 2 (as compared to 4.33% for Tier 1), and the new tier of benefits was projected to generate a present value savings of $136.5 million over 30 years (based on the 7.75% assumed rate of investment return on the OPEB plan's assets, which was in effect when Tier 2 was approved). According to the latest actuarial valuation and review of the Healthcare Benefits, which was completed by The Segal Company on November 6, 2023, for Fiscal Year 2023-24, the Normal Cost, as a percentage of payroll, was estimated to be 4.36% for Tier 2 (as compared to 4.77% for Tier 1).

Effective July 1, 2017, the Department follows the provisions of GASB Statement No. 75, *Accounting and Financial Reporting for Postemployment Benefits Other Than Pensions*, an amendment of GASB Statement No. 45 ("GASB No. 75"). GASB No. 75 requires employers with other postemployment liabilities to disclose the net postemployment liability along with deferred inflows and outflows of resources related to the other postemployment liability. The Department adopted the provisions of GASB No. 75 beginning for the Fiscal Year ended June 30, 2018. Accordingly, the cumulative effect of the impact on net position as of July 1, 2017 was negative $661.2 million. As of June 30, 2023, the Power System had a net OPEB liability surplus of $11.8 million comprised of $87.4 million surplus of retiree medical and $75.6 million liability in death benefits. As of June 30, 2022, the Power System had a net OPEB liability surplus of $172.6 million comprised of $235.7 million surplus of retiree medical and $63.1 million liability in death benefits. As approved by the Board, a regulatory asset has also been recorded, because this liability is expected to be funded by future revenues of the Power System. For more information about how GASB No. 75 affected the financial statements of the Power System, see "Note (6) Regulatory Assets and Liabilities" and "Required Supplementary Information" in the Department's Power System Financial Statements. Specifically, see Note 6(g) for a discussion of the Power System's establishment of the regulatory asset discussed above.

Transfers to the City

Pursuant to the Charter, the City Council may, subject to the provisions of contractual obligations, direct a transfer of surplus money in the Power Revenue Fund to the City's reserve fund (a "Power Transfer") with the consent of the Board. The Board may withhold its consent if it finds that making the Power Transfer would have a material adverse impact on the Department's financial condition in the year the Power Transfer is to be made. In the event the Board does not approve any year's Power Transfer, the City Administrative Officer is to verify the Department's findings and make a report thereon and recommendations with respect thereto. After receiving such report, and in consultation with the City Council and the Mayor, the Board shall either amend or uphold its preliminary findings.

Pursuant to covenants contained in the Master Resolution, a Power Transfer may not exceed the net income of the prior Fiscal Year or reduce the Power System's surplus to less than 33-1/3% of total Power System indebtedness. Subject to the restrictions of the Charter and the Master Resolution, the Board has most recently approved transfers totaling $244,695,000 to the City during the Fiscal Year ending June 30, 2024.

The following table shows the amounts of the Power Transfer in each of the last five Fiscal Years:

POWER TRANSFERS
FOR FISCAL YEARS ENDED JUNE 30, 2020 – 2024
($ in thousands)

Fiscal Year Ended June 30	Amount of Power Transfer
2020	$229,913
2021	218,355
2022	225,015
2023	232,043
2024	244,695

Source: Department of Water and Power of the City of Los Angeles.

The City does not include any funds in the Power Transfer that the Department collects pursuant to the Electric Rates established under the Incremental Electric Rate Ordinance, which was adopted in 2016. However, the Power Transfer includes surplus revenue generated from Electric Rates established under the Rate Ordinance adopted in 2008.

Insurance

The Department's insurance program generally consists of a combination of commercial insurance policies, a wildfire Catastrophe Bond ("CAT Bond") and self-insurance. All general liability claims within the Department's self-insured retention are administered under the Department's self-insurance program and the Department carries commercial excess general liability insurance above its self-insured retention. There are two separate towers of insurance. The first is for non-wildfire losses. After meeting the $3 million retention, the program has a primary layer of $35 million, which includes 50% of co-insurance for the 2024-25 policy year (April 2024 to April 2025). Co-insurance is a designated percentage of the policy that is retained by the Department and the remaining policy amount is recoverable from the insurer. Above the primary layer of $35 million are additional layers of commercial liability insurance that provide an additional $125 million of coverage, which has no co-insurance and would provide coverage up to the policy limits. The total limit available for non-wildfire losses is $160 million. There is a second tower of insurance that is solely for wildfire losses. The Department has a total of $100 million in self-insured retention that serves as its primary layer for wildfire coverage and above that primary self-insurance retention layer, the Department has procured an additional $105.5 million of commercial wildfire insurance, totaling an insurance tower of $205.5 million.

To complement its overall wildfire insurance program, the Department augments and supports its wildfire coverage with a CAT Bond. The previous $31.5 million indemnity wildfire CAT Bond, lasted for a three-year period, September 2021 to September 2024, and utilized an attachment point at $125 million. The CAT Bond is intended to cover a portion of any large claim for a fire event during the coverage period that might exceed the self-insurance and commercial insurance coverage. CAT Bonds are multi-year issuances and pay out based on a catastrophic fire event that occurs within the three-year period of the specific bond. CAT Bonds allow the Department to obtain additional wildfire coverage capacity outside of a commercial insurance policy, but, unlike commercial insurance, the Department achieves a premium cost that is fixed and known for the three-year period of the bond. The Department is currently pursuing a new CAT Bond issue of at least $50 million with an attachment point at $100 million. Through the utilization of commercial insurance and self-insurance, the wildfire insurance program currently has a total limit of $205.5 million available for wildfire losses. Once the pending CAT Bond issue is complete, it is expected to add at least $50 million.

For discussion regarding liability issues as they relate to wildfire losses, see "FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY – California Climate Change Policy Developments – *Legislation and Court Action Relating to Wildfires*."

Going forward, the Department will continue to consider any available coverage options in the market in order to ensure that the Department is adequately protected against catastrophic liability events and wildfires. In addition to the excess general liability insurance programs and the pending CAT Bond issuance, the Department continues to maintain a bona fide program of self-insurance as well. As of August 31, 2024, the portion of the Power Revenue Fund set aside for self-insurance had a balance of approximately $232.5 million in a restricted cash account. The Power Revenue self-insurance fund is specific to the Power Division and is primarily designed to cover a large catastrophic event that could affect the Power Division operations (*e.g.*, liability for a large wildfire). The Department annually reviews the amount retained for self-insurance and may adjust such amount if it deems such adjustment appropriate.

The Department has purchased a primary cyber insurance policy, with a self-insured retention component. This insurance policy covers certain types of cyber incidents and provides reimbursement coverage for costs to respond to data privacy or security incidents and for expenses incurred in connection with the investigation, prevention, and resolution of any cyber threat.

The Department commercially insures its physical plant through a policy of all risk property insurance, which is written on a replacement cost-basis. The policy covers all risk of physical loss or damage to buildings, structures, auxiliary and main plant equipment. Such insurance has a policy loss limit of $500 million for all claims in a single policy year. The all-risk property insurance has a deductible of $5 million. The Department has secured earthquake coverage and sudden and accidental pollution coverage as part of its all-risk property insurance program.

The Department's physical plant coverage does not provide coverage in certain events including terrorism or war. However, the Department has purchased a Terrorism Limits and Terrorism Risk Insurance Extension Act of 2005 ("TRIEA") Endorsement (the "Endorsement") to its excess general liability coverage under which coverage is extended to cover losses resulting from certain acts certified by the Secretary of the U.S. Department of the Treasury to be an act of terrorism, as defined in TRIEA. Currently, from 2002 through December 31, 2027, the Endorsement limits insurers liability for losses resulting from certified acts of terrorism when the amount of such losses exceeds $100 billion in any one calendar year. If the aggregate insured losses for all insurers exceed $100 billion, the Department's coverage may be reduced.

As a participant in the Palo Verde Nuclear Generating Station ("PVNGS") and associated transmission systems, the Department is an additional named insured on various forms of insurance providing protection against property and liability losses relating to such facilities. The amounts of coverage are established by participating owners and procured by the operating agent for the facility.

The Department, as the operating agent for the Intermountain Power Project ("IPP"), the Mead-Adelanto Transmission Project, the Marketplace Substation, the Pacific DC Intertie and in connection with its relationships with other entities and agencies, includes other entities or agencies as additional named insureds on the various forms of insurance procured for such facilities.

The Department continuously evaluates its insurance program and may modify the current configuration of commercial insurance and self-insurance with respect to the Power System. Insurance limits maintained by the Department are subject to change depending on market conditions and assessments by the Department as to risk exposure. The utilization of commercial insurance along with alternative risk options such as CAT Bonds allows the Department to strengthen its overall risk management program as well as provide flexibility in setting and adjusting its self-insurance retention limits as part of the continual review of the Department's insurance budget.

Investment Policy and Controls

Department's Trust Funds Investment Policy. The majority of the Power System funds are held in the Power Revenue Fund, investments of which are managed by the Office of Finance of the City. The funds have been invested as part of the City's investment pool program since 1983. Certain financial assets of the Department that are held in special-purpose trust or escrow funds with an independent trustee ("Trust Funds") more fully described in "Note (7) Cash, Cash Equivalents, and Investments" of the Department's Power System Financial Statements ("Note 7"), are not included in the City's investment pool program. The Department manages the investment of the Trust Funds in which approximately $694.5 million (investments at fair market value) was on deposit as of May 31, 2024. The Department's investment of such funds complies with the California Government Code in all material respects and such funds are invested according to the Department's Trust Funds Investment Policy (the "Trust Funds Investment Policy"), which sets forth investment objectives and constraints. For more information about the Trust Funds Investment Policy, see Note 7. Such funds consist of debt reduction trust funds, the nuclear decommissioning trust funds, the natural gas trust fund, the California Independent System Operating Markets trust fund, and the hazardous waste treatment storage and disposal trust fund. These trust funds are being held by U.S. Bank Trust Company, National Association as trustee/custodian. Amounts in the debt reduction trust fund are to be applied at the discretion of the Chief Financial Officer, to the retirement (including the payment of debt service, purchase, redemption and defeasance) of Power System debt, including obligations to Intermountain Power Agency ("IPA") and Southern California Public Power Authority ("SCPPA"). As of May 31, 2024, the debt reduction trust fund had a balance of approximately $513.3 million (investments at fair market value as of such date).

Under the Trust Funds Investment Policy, the Department's investment program seeks to accomplish three specific goals: (i) preserve the principal value of the funds, (ii) ensure that investments are consistent with each individual fund's liquidity needs and (iii) achieve the maximum yield/return on the investments.

The overall responsibility for managing the Department's investment program for the Trust Funds rests with the Department's Chief Financial Officer, who directs investment activities through the Department's Assistant Chief Financial Officer and Treasurer. An Investment Committee, comprised of the City Controller, a Board member designated by the Board President, the General Manager and the Department's Chief Financial Officer (the "Department Investment Committee") is charged with oversight responsibility. The Trust Funds Investment Policy is adopted by the Board from time to time, and fund activity is reviewed periodically by the Department Investment Committee to ensure its consistency with the overall objectives of the policy, as well as its relevance to current law and financial and economic trends.

The Department's Assistant Chief Financial Officer and Treasurer or its designee reviews all investment transactions for the Trust Funds on a monthly basis for control and compliance and submits quarterly investment reports that summarize investment income to the Department Investment Committee, the Board and the Mayor for information and evaluation.

POWER SYSTEM TRUST FUNDS INVESTMENTS
ASSETS AS OF MAY 31, 2024
(DOLLARS IN THOUSANDS)
(UNAUDITED)

	Fair Market Value
U. S. Government Securities	$ 20,747
U. S. Sponsored Agency Issues	392,993
Supranationals	11,297
Medium term corporate notes	109,613
Municipal obligations	53,970
California state bonds	9,825
Other state bonds	34,544
Commercial paper	--
Certificates of deposit	33,524
Money market funds	27,989
Total	$694,501

Source: Department of Water and Power of the City of Los Angeles.
* Totals may not equal sum of parts due to rounding.

Department Financial Risk Management Policies. In order to manage certain financial and operational risk, the Board has adopted a number of policies in addition to its Trust Funds Investment Policy. The Board has adopted a Counterparty Evaluation Credit Policy designed to minimize the Department's credit risk with its counterparties. This policy applies to wholesale energy, transmission, physical natural gas and financial natural gas transactions entered into by the Department. Pursuant to this policy the Department assigns credit ratings to such counterparties. The policy requires the use of standardized netting agreements which require such counterparties to net positive and negative exposures to the Department and requires credit enhancement from counterparties that do not meet an acceptable level of risk. Sales to such counterparties are only permitted up to the amount of purchases with a netting agreement and, in certain cases, credit enhancement in place.

The Board has adopted a Retail Natural Gas Risk Management Policy designed to mitigate the Department's exposure to unexpected spikes in the price of natural gas used in the production of electricity to serve retail customers. This policy authorizes Department management to enter into transactions for natural gas subject to specified parameters, such as duration of contract and price and volumetric limits. It also establishes internal controls for natural gas risk management activity. See "THE POWER SYSTEM – Fuel Supply for Department-Owned Generating Units and Apex Power Project."

The Board has adopted a Wholesale Marketing Energy Risk Management Policy to establish a risk management program designed to manage the Department's exposure to risks resulting from purchases and sales of wholesale energy, transmission services and ancillary services. This policy establishes the General Manager's authority to enter into such transactions, identifies approved transaction types and establishes internal controls for wholesale energy risk management activity.

The Board has adopted an Environmental Credit and Renewable Energy Credit Policy to establish a risk management program that is designed to manage the Department's exposure to risks resulting from purchases and sales of emissions credits or allowances and other credits available for the purpose of compliance with environmental laws, rules, and regulations. This policy establishes the General Manager's authority to enter into such transactions, identifies approved transaction types, and establishes internal controls surrounding credit risk management activity.

The Board has adopted a Dodd-Frank Act Compliance Policy to ensure the Department complies with applicable provisions of the Dodd-Frank Wall Street Reform and Consumer Protection Act and commodity futures trading commission requirements.

City Investment Policy. The Office of Finance of the City invests temporarily idle cash on behalf of the City, including that of the proprietary departments, such as the Department, as part of a pooled investment program. As of May 31, 2024, the Power System had approximately $1.52 billion of unrestricted cash and approximately $1.03 billion of restricted cash on deposit with the City. This month-end amount does not reflect the GASB Statement No. 31 fair market value adjustment. For information regarding the fair market value adjustment of the Department's pooled investment fund assets as of June 30, 2023, see Note 7(b) in the Department's Power System Financial Statements. This amount is in addition to what is on hand in the Trust Funds, see "– *Department's Trust Funds Investment Policy*" above. The City's pooled investment program combines general receipts with special funds for investment purposes and allocates interest earnings and losses on a pro-rata basis when the interest is earned and distributes interest receipts based on the previously established allocations. The primary responsibilities of the Office of Finance of the City and the pooled investment program are to protect the principal and asset holdings of the City's portfolio and to ensure adequate liquidity to provide for the prompt and efficient handling of City disbursements. Funds invested by the Power System in the pooled investment program are available for withdrawal within five business days without penalties. In addition, 20% of the pool, as of June 30, 2023, had maturities less than one month and 39% of the pool, as of June 30, 2023, had maturities of one year or less.

CITY OF LOS ANGELES POOLED INVESTMENT FUND
ASSETS AS OF JUNE 30, 2023
(Dollars in Thousands)
(Unaudited)

	Amount	**Percent of Total**	**Power System Share**
U.S. Treasury Notes	$ 8,939,146	58.52%	$ 1,591,211
Commercial Paper	987,939	6.47	175,925
Medium-Term Notes	1,709,101	11.19	304,266
U.S. Agencies Securities	1,918,910	12.56	341,517
Supranationals	219,575	1.44	39,155
Short-Term Investment Funds	1,134,771	7.43	202,028
Asset-Backed Securities	305,709	2.00	54,382
Securities Lending Short-Term Repurchase Agreement	59,668	0.39	10,604
Negotiable Certificates of Deposit	0	0.00	0
Total General and Special Pools*	**$15,274,819**	**100.00%**	**$2,719,088**

Source: Department of Water and Power of the City of Los Angeles and Los Angeles City Treasurer.
Note: Department funds held by the City are both unrestricted and restricted funds. Totals may not equal sum of parts due to rounding.
Note: Fair Market Value as of June 30, 2023.

The City's investment operations are managed in compliance with the California Government Code and the City's statement of investment policy, which sets forth permitted investments, liquidity parameters and maximum maturity of investments. The investment policy is reviewed and approved by the City Council on an annual basis.

Monthly reports of investment activity are presented to the Mayor, the City Council and the Department to indicate, among other things, compliance with the investment policy. The City's Office of Finance does not invest in structured and range notes, securities that could result in zero interest accrual if held to maturity, variable rate, floating rate or inverse floating rate investments or mortgage-derived interest or principal-only strips.

The investment policy permits the City's Office of Finance to engage custodial banks to enter into short-term arrangements to lend securities to various brokers. Cash and/or securities (United States Treasuries and Federal Agencies only) collateralize these lending arrangements, the total value of which is required to be at least 102% of the market value of securities loaned out. The securities lending program is limited to a maximum of 20% of the market value of the City's Office of Finance's pool by the City's investment policy and the California Government Code.

For more information about the investments in the City's Office of Finance pool, see Note 7.

ELECTRIC RATES

Rate Setting

Pursuant to the Charter, the Board, subject to the approval of the City Council by ordinance (as discussed below), fixes the rates for electric service from the Power System ("Electric Rates"). The Charter provides that the Electric Rates shall be fixed by the Board from time to time as necessary. The Charter also provides that the Electric Rates shall, except as authorized by the Charter, be of uniform operation for customers of similar circumstances throughout the City, as near as may be, and shall be fair and reasonable, taking into consideration, among other things, the nature of the uses, the quantity supplied and the value of the service provided. The Charter further provides that rates for electric energy may be negotiated with individual customers, provided that such rates are established by binding contract, contribute to the financial stability of the Power System and are consistent with such procedures as the City Council may establish.

The Board is obligated under the Charter and the rate covenant in the Master Resolution to establish Electric Rates and collect charges in amounts which, together with other available funds, shall be sufficient to service the Department's Power System indebtedness and to meet the Power System's expenses of operation and maintenance. The Charter provides that Electric Rates are subject to the approval of the City Council by ordinance (a "Rate Ordinance"). The Charter further requires that the City Council approve Rate Ordinances for the Electric Rates prescribed in the rate covenant in the Charter, which rate covenant is also included in the Master Resolution.

The Department's completed interim rate review of the last rate action for Fiscal Year 2015-16 through Fiscal Year 2019-20 resulted in planned annual system average Electric Rate increase adjustments. The average yearly increase during the five-year period was approximately 4.5% for low-energy users, approximately 4.0% for midrange users, and approximately 5.5% for top tier users, reflected in increased actual pass-through cost adjustments and decreased Base Rate revenue targets.

The rate increase over these five Fiscal Years is reflected in the Incremental Electric Rate Ordinance and as a result, effective April 15, 2016, the Department's retail electric revenue requirement has been funded from the Rate Ordinance adopted in 2008 and the Incremental Electric Rate Ordinance through the following major components:

(a) Under the Rate Ordinance adopted in 2008:

(i) Base Rates: Base Rates are used to fund expenditures including debt service arising from capital projects (except projects relating to the Renewable Portfolio Standard ("RPS")), operational and maintenance expenses (except as RPS-related), public benefit spending, property tax, and a prorated portion of the Power Transfer;

(ii) Reliability Cost Adjustment (the "RCA"): The RCA is used to recover certain power reliability expenditures; and

(iii) Energy Cost Adjustment (the "ECA"): The ECA is used to recover expenditures for fuel, non-renewable purchased power, RPS and energy efficiency-related expenditures.

(b) Under the Incremental Electric Rate Ordinance:

(i) Incremental Base Rates: The Incremental Base Rates are used to recover costs of providing electric utility service that are not recovered by Base Rates or any of the Rate Ordinance cost adjustments, including labor costs, real estate costs, costs to rebuild and operate local power plants, equipment costs, operation and maintenance costs, expenditures for jointly-owned plants and other inflation-sensitive costs, in addition to including the Power Access Charge, which is a consumption-based tiered charge applied to residential non-Time-of-Use Residential Rate customers used to recover basic infrastructure costs for providing access to the power grid;

(ii) Incremental Reliability Cost Adjustment (the "IRCA"): The IRCA is used to recover costs associated with operations and maintenance, debt service expense of the Power System Reliability Program and RCA under-collection;

(iii) Variable Energy Adjustment (the "VEA"): The VEA is used to recover costs associated with fuel, non-renewable portfolio standard power purchase agreements, economy purchases, legacy ECA under-collection and Base Rates decoupling from energy efficiency impact;

(iv) Capped Renewable Portfolio Standard Energy Adjustment (the "CRPSEA"): The CRPSEA is used to recover costs associated with RPS operations and maintenance, debt service and energy efficiency programs; and

(v) Variable Renewable Portfolio Standard Energy Adjustment (the "VRPSEA"): The VRPSEA is used to recover costs associated with RPS market purchases and costs above any operations and maintenance and debt service payments.

The RCA, ECA, IRCA, VEA, CRPSEA and VRPSEA are pass-through cost adjustments applied by factors that the Department may change with approval of the Board, without changes to existing Rate Ordinances.

Recent Rate Actions. On the recommendation of the Office of Public Accountability (the "OPA"), the Board decreased the Base Rate revenue targets for Fiscal Year 2018-19 and Fiscal Year 2019-20 by 2% each. The OPA further recommended, and the Department supports the recommendation, to use four-year rate action cycles, rather than replicate the recent five-year rate action cycle. In June 2022, the Board approved an increase of the Base Rate revenue target for Fiscal Year 2022-23 of 2.035%, in accordance with the provisions of the Incremental Electric Rate Ordinance. In June 2023, the Board approved an increase of the Base Rate revenue target for Fiscal Year 2023-24 of 5.60% in accordance with the provisions of the Incremental Electric Rate Ordinance. In June 2024, the Board approved an increase of the Base Rate revenue target for Fiscal Year 2024-25 of 1.48% in accordance with the provisions of the Incremental Electric Rate Ordinance. The increase to the Base Rate revenue target will continue to provide the Department with sufficient revenues to meet the rate covenant under the Master Resolution and the Board adopted financial metrics. The Department is in the process of reviewing the Rate Ordinance and Incremental Electric Rate Ordinance and, based on current and assumed market conditions, determining what changes, if any, need to be made in connection with the next rate action. Department staff expects to review the need and proposed schedule for the next rate action with the General Manager in the second half of calendar year 2024.

Proposition 26. In 2010, California voters approved Proposition 26 ("Proposition 26"), an initiative measure amending Article XIII C of the State Constitution to add a new definition of "tax." Each such tax cannot be imposed, extended, or increased by a local government without voter approval. Article XIII C of the State Constitution, as amended by Proposition 26, defines "tax" to include any levy, charge, or exaction imposed by a local government, except, among other things, (a) charges imposed for benefits conferred, privileges granted, or services or products provided, to the payor (and not to those not charged) that do not exceed the reasonable costs to the local government of conferring, granting or providing such benefit, privilege, service, or product, and (b) property-related fees imposed in accordance with the provisions of Article XIII D of the State Constitution. The Department believes that the Electric Rates and charges do not constitute taxes as defined in Article XIII C of the State Constitution.

Board Adopted Financial Planning Criteria. The Board has directed the Department to use the following criteria when preparing the Power System's financial plans with respect to Electric Rates: (i) maintain a minimum operating cash target of the equivalent of 170 days of operating expenses, (ii) maintain full obligation coverage of at least 1.7 times, and (iii) maintain a debt-to-capitalization ratio of less than 68%. These criteria are subject to reviews and adjustments from time to time by the Board with advice from the Department's financial advisors and were most recently revised on May 26, 2020.

Neighborhood Councils. Pursuant to a Memorandum of Understanding with the City's Neighborhood Councils, the Department agrees to use its best efforts to undertake a 60-day or 90-day notification and outreach period (depending on the duration of the Department's proposed rate action) prior to submitting a residential or non-residential retail business customer electric rate increase proposal involving changes to the Rate Ordinances to the Board for approval. The Neighborhood Councils have indicated they will use their best efforts to provide written input regarding such rate proposals to the Department within 60 days of receiving the above-discussed notifications.

Office of Public Accountability. Section 683 of the Charter establishes the OPA with respect to the Department. The primary role of the OPA is providing public, independent analysis to the Board and City Council about Department actions as they relate to the Electric Rates and water rates. The role of the OPA is advisory rather than as an approver of Electric Rates. The OPA is headed by an Executive Director appointed by a citizens committee, subject to confirmation by the City Council and Mayor. The Executive Director of the OPA serves as the Ratepayer Advocate for the OPA. On February 1, 2012, Dr. Frederick H. Pickel was appointed as Executive Director of the OPA (the "Ratepayer Advocate"); and on December 5, 2018, Dr. Pickel was reappointed as the Ratepayer Advocate for a five-year term. Dr. Pickel's term as Executive Director of OPA and Ratepayer Advocate expired on December 5, 2023; however, Dr. Pickel will continue to serve in those roles until his retirement, which is expected to occur before the end of calendar year 2024. The rate action effective April 15, 2016 was supported by the Ratepayer Advocate following his review of the proposed rate changes. The rate action included certain changes proposed by the Ratepayer Advocate. As a result of the rate action involving the Incremental Electric Rate Ordinance for Fiscal Year 2015-16 through Fiscal Year 2019-20, the Department is required to provide semi-annual written reports each year regarding certain Board-established metrics to the Board and the OPA.

Rate Regulation

While changes in the retail Electric Rate ordinances are subject to approval by the City Council, the authority of the Board to impose and collect retail Electric Rates for service from the Power System is not subject to the general regulatory jurisdiction of the California Public Utilities Commission (the "CPUC") or any other State or federal agency. The California Public Utilities Code (the "Public Utilities Code") contains certain provisions affecting all municipal utilities such as the Power System. At this time, neither the CPUC nor any other regulatory authority of the State nor the Federal Energy Regulatory Commission ("FERC") approves the Department's retail Electric Rates. It is possible that future legislative and/or regulatory changes could subject the Department to the jurisdiction of the CPUC or to other limitations or requirements.

The California Energy Resources Conservation and Development Commission, commonly referred to as the California Energy Commission (the "CEC"), is authorized to evaluate rate policies for electric energy as related to the goals of the Warren-Alquist State Energy Resources Conservation and Development Act (Public Resources Code Section 25000 et seq.) and make recommendations to the Governor of the State, the Legislature and publicly-owned electric utilities ("POUs") such as the Department.

Although its retail Electric Rates are not subject to approval by any state or federal agency, the Department is subject to certain provisions of the Public Utilities Code and the Public Utility Regulatory Policies Act of 1978 (“PURPA”). PURPA applies to the purchase of the output of “qualified facilities” (“QFs”) at prices determined in accordance with PURPA. The Energy Policy Act of 2005 repealed the mandatory purchase obligation for electric utilities when FERC determines that the QFs have non-discriminatory access to wholesale power markets with certain characteristics. The Department has neither applied for nor been relieved of its mandatory purchase obligation. The Department believes that it is currently operating in compliance with PURPA.

Under federal law, FERC has the authority, under certain circumstances and pursuant to certain procedures, to order any utility (municipal or otherwise), including the Department, to provide electric transmission access to others at cost-based rates. FERC also has licensing authority over hydroelectric facilities and regulates the reliability and security of the nation’s bulk power system.

With, among other things, the consent of the Department, operational control of the transmission facilities owned or controlled by the Department may be transferred to the California statewide network administered by the California Independent System Operator Corporation (“Cal ISO”). See “THE POWER SYSTEM – Transmission and Distribution Facilities.” In 2017, the Department updated its Open Access Transmission Tariff (“OATT”), which included revising the cost-of-service and rate design for the Department’s wholesale transmission rates. In 2020, the Department updated its OATT to facilitate entry into Cal ISO’s Western Energy Imbalance Market (the “EIM”). The April 2020 amendment to the Department’s OATT focused predominantly on non-rate terms and conditions related to the EIM, to ensure that services under the OATT would continue to be provided in a comparable and not unduly discriminatory or preferential manner to all of the Department’s OATT customers. The April 2020 amendment largely followed similar, prior OATT amendments of other utilities already participating in the EIM. The OATT has been and may be amended or updated from time-to-time. For more information on the Department’s entry into the Western EIM, see “THE POWER SYSTEM – Transmission and Distribution Facilities.”

Billing and Collections

General. With some limited exceptions, the Department currently bills residential customers on a bimonthly basis and commercial and industrial customers on a monthly basis. The Department prepares bills covering water and electric charges and non-Department charges (such as sewer services, solid waste resources fee and State and local taxes). Payments are posted in the following order: overdue receivables, customer deposits, water charges, electric charges, State and local taxes, sewer service charges, solid waste resources fees and bulky item fees. Within overdue receivables, payments received are applied in the same order for which payments are posted for current receivables.

In September 2022, the Department launched a new Level Pay system that provides eligible residential customers the opportunity to pay a monthly recurring amount for utility services based on an average of the customer’s past usage and costs over the previous 12 months. Payment terms of 12, 24 and 36 months are available. At the end of the payment term, Level Pay will automatically renew and the monthly amount will be recalculated. Any underpayment or overpayment will be rolled into the calculation of the next term. The customer may cancel Level Pay at any time. It is not known at this time how many customers will ultimately sign up for Level Pay. Participation to date has been minimal but is continuing to increase. The Department does not anticipate Level Pay to have a materially adverse impact on its finances or operations.

Billing System. In September 2013, the Department launched a new customer information and billing system, designed and implemented by Pricewaterhouse Coopers LLP. Immediately following the launch of the new billing system, the Department experienced numerous billing issues in connection with the new system, including, but not limited to, (a) the inability to issue bills to customers, (b) the inability to issue accurate bills to customers, (c) an increase in estimated bills that were sent to customers where metering information was not available, and (d) the inability to generate multiple business reports, including financial reports reflecting the Department’s accounts receivable. The customer information and billing system is currently being used by the

Department. The Department continues to work to improve the functionality of the system to meet the Department's original expectations for the system.

Delinquencies. Based on annual historical experience of delinquencies, the Department historically has been unable to collect approximately 0.7% of the amounts billed to its customers. In light of the prior billing issues noted above and in response to the COVID-19 pandemic described below, the allowance for doubtful accounts has been increased to 2.0% of Power System sales since Fiscal Year 2020-21, creating an allowance of $280.4 million for the Fiscal Year ended June 30, 2023. The Power System's accounts receivable (including utility user's tax) as of June 30, 2023 were $1.05 billion compared to $855.7 million as of June 30, 2022. Of these amounts, $608.6 million (58.05% of total receivables) and $445.2 million (52.03% of total receivables) were 120 days or more past the payment due date as of June 30, 2023 and June 30, 2022, respectively. As of May 31, 2024, the Power System's allowance for doubtful accounts was $298.6 million and accounts receivable were $1.23 billion (including utility user's tax). Of these amounts, $740.4 million (60.36% of total receivables) were 120 days or more past the payment due date. As of May 31, 2023, the Power System's allowance for doubtful accounts was $309.7 million and accounts receivable were $1.02 billion (including utility user's tax). Of these amounts, $587.5 million (57.55% of total receivables) were 120 days or more past the payment due date.

COVID-19 Effects. In response to the COVID-19 pandemic, the Department deferred disconnection of water and power services to customers who were unable to pay their bills due to financial hardship, which deferrals officially ended on March 31, 2022 (the Department began the resumption of disconnections for commercial customers in June 2023 and has initiated the first phase of a plan to resume service disconnections for residential customers in the near future). As a result of the deferral of disconnections, the Department has experienced an increase in the amount of bills that are 120 days or more past their payment due date as described above under "Delinquencies." Ultimately, customers are still responsible to pay the billed amounts and the Department will work with customers by providing payment options. See "FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY – Global Health Emergencies; COVID-19 Pandemic."

The California Legislature established the 2021 California Arrearage Payment Program ("2021 CAPP") to provide financial assistance for California energy utility customers to help reduce past due energy bill balances during the COVID-19 pandemic. Administered by the Department of Community Services and Development (the "CSD"), the 2021 CAPP dedicated approximately $994 million in federal American Rescue Plan Act funding to address Californian's energy debts, of which approximately $299 million was allocated for financial assistance to customers of POUs and electrical cooperatives. In September 2021, the Department submitted a funding request of approximately $203 million for residential arrearages and approximately $109 million for commercial arrearages. The Department received $202.8 million of 2021 CAPP funding of which $201.5 million have been credited towards residential arrearages. As authorized by the CSD, the Department distributed the remaining $1.3 million towards residential and commercial arrearages in March 2022.

The California Legislature established the 2022 California Arrearage Payment Program ("2022 CAPP"), which dedicated approximately $1.2 billion to address Californian's energy debts. In October 2022, the Department submitted a funding request of approximately $76.6 million for residential arrearages. The Department received the requested 2022 CAPP funding amount and credited residential arrearages in January 2023.

Write-Off Procedures. Uncollectible accounts are recoverable by the Department by passing on such "bad debts" to the ratepayers via pass-through adjustment factors. Due to hot weather in the summer and associated higher bills and the Department's bimonthly billing process, accounts receivable balances generally increase in the late summer and autumn and generally decrease in the winter and spring. These accounts receivable balances include inactive accounts. Inactive accounts that are included in accounts receivable that cannot be linked to an active account will be written off as uncollectible.

Customer Bill of Rights. In January 2017, the Board adopted a "Customer Bill of Rights" which was developed by the Department in consultation with then Mayor Eric Garcetti and is designed to improve service for Department customers. On February 26, 2019, the Board extended the "Customer Bill of Rights" indefinitely.

THE POWER SYSTEM

General

The Power System is the nation's largest municipal electric utility with a net maximum plant capacity of 10,864 megawatts ("MW") and net dependable capacity of 8,075 MW as of May 31, 2024, and properties with a net book value of approximately $14.2 billion as of May 31, 2024. The Power System's highest load registered 6,502 MW on August 31, 2017. Based on the Department's December 2023 Retail Electric Sales and Demand Forecast, the Department anticipated that gross customer electricity consumption would increase from Fiscal Year 2021-22 to Fiscal Year 2031-32 at a forecasted rate of approximately 1.58% per year without consideration of the Department's measures to promote energy efficiency and distributed generation. That load growth rate reflects, in the later part of the ten year planning period, increases due in part to fuel switching in the transportation sector including the increase of plug-in hybrid and battery electric vehicles. In accordance with the Power System's recent resources plans, significant energy efficiency measures have been planned and are being implemented as a cost effective resource, along with support for customer solar projects. The Department adopted a goal in August of 2014 of achieving up to 15% energy savings by the end of 2020, which was achieved. The Department is now focused on a goal of achieving additional energy savings of 3,434 gigawatt hours ("GWhs") from 2023 to 2035, surpassing the 1,802 GWhs of projected savings reflected in the LA100 Study. For the operating statistics of the Power System, see "OPERATING AND FINANCIAL INFORMATION – Summary of Operations."

The Department estimated that the Power System's capacity (as of May 31, 2024) and energy mix (actual numbers for calendar year 2022) were approximately as follows:

DEPARTMENT GENERATION MIX PERCENTAGES

Resource Type	Capacity Percentage[(1)]	Energy Percentage[(2)]
Natural Gas	36%	34.5%
Large Hydro	16	4.0
Coal	11	12.6
Nuclear	4	13.3
Renewables	33	35.6
Storage	<1	–
Unspecified Sources of Energy[(3)]	–	–
Total	100%	100%

(1) Net Maximum Unit Capability as of May 31, 2024.
(2) Energy percentage is based on the Department's calendar year 2022 fuel mix submission as part of the 2022 Annual Power Content Label (APCL) to the California Energy Commission in September 2023.
(3) Unspecified sources of energy means electricity from transactions that are not traceable to specific generation sources.
Note: Totals may not equal sum of parts due to rounding.

The Department anticipates that its generation mix will change in response to statutory and regulatory developments. See "FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY."

Generation and Power Supply

The Power System has a number of generating resources available to it. The following discussion describes the Department's solely owned, jointly owned and contracted generation facilities, as well as fuel and water supplies and spot purchase activities. Currently, the Department's base load requirements are fulfilled primarily by generating capacity at IPP and PVNGS, and balanced with its natural gas, hydroelectric, renewable resources and spot purchases. The following information concerning the capacities of various facilities is as of May 31, 2024.

Department-Owned Generating Units

The Department's solely owned generating facilities, as of May 31, 2024, are summarized in the following table:

DEPARTMENT OWNED FACILITIES

Type of Fuel	Number of Facilities	Number of Units	Net Maximum Capacity (MW)(1)	Net Dependable Capacity (MW)(1)
Natural Gas	4(2)	29(2)	3,373	3,191
Large Hydro	1	7	1,265	1,265
Renewables	66	163(3)	417	277(4)
Storage	1	1	20	20
Subtotal	**72**	**200**	**5,075**	**4,753**
Less: Payable to the California Department of Water Resources	–	–	(120)(5)	(48)(5)
Total	**72**	**200**	**4,955**	**4,705**

Source: Department of Water and Power of the City of Los Angeles.

(1) Based on 2023-24 capacity ratings.

(2) Consists of the four Los Angeles Basin Stations (Haynes, Valley, Harbor and Scattergood) discussed and defined below. See "*– Once-Through-Cooling Units Phase-Out*" below for information regarding the future expected phase out of certain natural gas units.

(3) Includes 22 of the hydro units at the Los Angeles Aqueduct, Owens Valley and Owens Gorge hydro units that are certified as renewable resources by the CEC. Also included are Department-built photovoltaic solar installations, the Pine Tree Wind Project and a local small hydro plant. Not included are the units that were upgraded at the Castaic Plant.

(4) Figure based on statistical modeling of likely output without consideration of weather conditions that may affect the ability of certain renewable resources to reach its dependable capacity.

(5) Energy payable to the California Department of Water Resources for energy generated at the Castaic Plant. This amount varies weekly up to a maximum of 120 MW.

Los Angeles Basin Stations. The Department is the sole owner and operator of four electric generating stations in the Los Angeles Basin (the "Los Angeles Basin Stations"), with a combined net maximum generating capacity of 3,373 MW and a combined net dependable generating capacity of 3,191 MW. Natural gas is used as fuel for the Los Angeles Basin Stations. Ultra-low-sulfur distillate is used for emergency back-up fuel. See "– Fuel Supply for Department-Owned Generating Units and Apex Power Project." See also "– Projected Capital Improvements." The four Los Angeles Basin Stations are briefly described below.

Haynes Generating Station. The largest of the Los Angeles Basin Stations is the Haynes Generating Station, located in the City of Long Beach, California. The Haynes Generating Station currently consists of eleven generating units with a combined net maximum capacity of 1,614 MW and a net dependable capacity of 1,507 MW. Originally comprising six units, two of the original units were repowered in 2005 and replaced with a combined-cycle generating unit, which includes two combustion turbines and a common steam turbine. The combustion turbines can each operate with the steam turbine independently or together in a two–plus–one configuration (and are counted by the Department as three generating units). In 2013, the Department completed the replacement of an additional two of the original units with six advanced simple-cycle gas turbine units. In 2022, the Department completed the demolition of the four Haynes Generating Station Units that were decommissioned to create a construction area for a future energy project. See "FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY – Environmental Regulation and Permitting Factors – *Water Quality – Cooling Water Process – State Water Resources Control Board" and "– Regional Requirements – Thermal Discharges at Harbor Generating Station and Haynes Generating Station*" for a discussion of potential permitting and related equipment upgrades with respect to cooling water intake structures and thermal discharges.

Valley Generating Station. The Valley Generating Station is located in the San Fernando Valley and is currently comprised of a simple-cycle generating turbine unit and a combined-cycle generating unit, which consists of two combustion turbines and a common steam turbine. The combustion turbines can each operate with the steam turbine independently or together in a two-plus-one configuration (and are counted by the Department as three generating units). The net maximum plant capacity for the Valley Generating Station is 555 MW. The total net dependable capacity for the Valley Generating Station is 528 MW. The Department expects to demolish four Valley Generating Station Units that were decommissioned in 2002 to create a construction area for a future energy project. The demolition of the decommissioned Valley Generating Station Units is not expected to impact the energy output of the Valley Generating Station. Demolition is expected to be completed by November 2026.

Valley Generating Station Gas Vent-Off. While conducting methane surveys across the State for the CEC in August 2020, the Jet Propulsion Laboratory observed an increase of methane vent-off over the Valley Generating Station reciprocating natural gas compressor area. The Department installed new design rod packing seals in December 2020 that have been working as designed.

Five Los Angeles Superior Court cases were filed related to the referenced vent-off at the Valley Generating Station. The most significant of the cases, a class action lawsuit with a putative class of 30,000 individuals, was dismissed in December 2021. Additionally, punitive damages were removed, and the number of causes of action was reduced. Those court actions significantly eliminate the financial recovery expected by plaintiffs' counsel. With the dismissal of the class action lawsuit, there are four remaining cases, including *Pueblo y Salud, Inc, et. al. v. Los Angeles Department of Water and Power, et al.*, 21STCV04346, the lead case. There are approximately 3,200 individual plaintiffs represented by various counsel. The final number of individual plaintiffs is expected to be approximately 1,300 after plaintiffs who have not participated in discovery are dismissed. The court is holding regular status conferences to determine the future schedule of the pending matters. All pending cases have been deemed related by the court and are assigned to the same judge in the Los Angeles Superior Court. No final status conference or trial date have been set.

The Department's exposure for the Valley Generation Station, if there is liability, is not now known. The Department has notified insurance carriers which may afford possible coverage for the underlying incident(s), however, at the present time no insurance coverage nor the amount of coverage, if any, has been confirmed.

Harbor Generating Station. The Harbor Generating Station is located in Wilmington, California. The Harbor Generating Station is comprised of eight generating units, including five simple-cycle generating turbine units and a combined-cycle unit, which includes two combustion turbines and a common steam turbine. The combustion turbines can each operate with the steam turbine independently or together in a two-plus-one configuration (and are counted by the Department as three generating units). Harbor Generating Station's net maximum capacity is 426 MW with a net dependable capacity of 422 MW. See "FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY – Environmental Regulation and Permitting Factors – *Water Quality – Cooling Water Process– State Water Resources Control Board*" and "*– Regional Requirements – Thermal Discharges at Harbor Generating Station and Haynes Generating Station*" for a discussion of potential permitting and related equipment upgrades with respect to cooling water intake structures and thermal discharges.

Scattergood Generating Station. The Scattergood Generating Station is located in Playa Del Rey, California and is currently comprised of two conventional steam boiler generating units, one combined-cycle unit, which consists of two generating units in a one-plus-one configuration, and two advanced simple-cycle gas turbines, for a total of six generating units, with a net maximum capacity of 778 MW and a net dependable capacity of 734 MW from natural gas. An original unit of the Scattergood Generating Station was decommissioned in 2015 and has been demolished to create the construction area for a future energy project. See "FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY – *Environmental Regulation and Permitting Factors – Water Quality – Cooling Water Process – State Water Resources Control Board*" for a discussion of potential permitting and related equipment upgrades with respect to cooling water intake structures.

Once-Through-Cooling Units Phase-Out. Generating units at the Los Angeles Basin Stations that currently utilize once-through-cooling have a net maximum capacity of 1,486 MW. In February 2019, then Mayor Eric Garcetti announced that these units would be phased out and replaced with energy storage and clean energy alternative assets. The Department has initiated the City's planning efforts for replacing the capacity of the once-through cooling units as they retire by December 31, 2029. The Department presented a 2022 Power Strategic Long-Term Resource Plan (the "2022 Strategic Long-Term Resource Plan") to the Board in September 2022, which details high level initiatives, including increased use of energy storage, retrofitting existing gas units that currently use once-through-cooling with alternative cooling designs such as using wet cooling towers, and introducing hydrogen capable gas generating units to replace once-through-cooling units, and to formalize a roadmap for achieving 100% carbon free energy by 2035. The 2022 Strategic Long-Term Resource Plan was finalized and released in July 2023. See also "– Renewable Power Initiatives – *Strategic Long-Term Resource Plan*."

Other Department-Owned Generating Facilities. In addition to the Los Angeles Basin Stations, the Department is the sole owner of a number of other generating facilities. Certain of the Department's hydroelectric projects are described below. See also "– Renewable Power Initiatives."

Castaic Pump Storage Power Plant. The Castaic Pump Storage Power Plant is located near Castaic, California (the "Castaic Plant") just before the terminus of the west branch of the California Aqueduct at Castaic Lake. The Castaic Plant is the Department's largest source of hydroelectric capacity and consists of seven units. The Castaic Plant's net maximum capacity and net dependable capacity for the seven units is 1,265 MW. The seven units completed a modernization process in August 2016. A FERC license pursuant to which the Department operates the Castaic Plant expired in 2022. The Department, in partnership with the California Department of Water Resources (the "CDWR"), is in the process of renewing this FERC license. FERC has not yet issued a new license. Under federal regulations, FERC issued an annual license on February 3, 2022, for the continued operations of Castaic Power Plant under the current license conditions. This annual license will be automatically renewed until FERC issues a new license. The Castaic Plant provides peaking and reserve capacity and is normally not a source of energy to the Department's net base load requirements. The Castaic Plant obtains water supply via the water conveyance system (the "State Water Project") operated by the CDWR, which has frequently been the subject of litigation that generally alleges that the CDWR is illegally "taking" listed species of fish through operation of the State Water Project export facilities and that the CDWR should cease operation of the State Water Project pumps. The CDWR has altered the operations of the State Water Project to accommodate certain listed species, which has had the effect of reduced pumping from the affected waters. Future litigation of this nature could influence how the State Water Project is operated and further reduce water flow to the Castaic Plant. The Department cannot predict at this time what effect this type of litigation will have on the Power System. See "– Water Supply for Department-Owned Generating Units" below.

Owens Gorge and Owens Valley Hydroelectric Generation. The three Owens Gorge and seven Owens Valley hydroelectric generating units (the "Owens Gorge and Owens Valley Hydroelectric Generation") are located along the Owens Valley in the Eastern High Sierra region of the State. The aggregate net dependable capacity of Owens Gorge and Owens Valley Hydroelectric Generation totals 35 MW and the net maximum capacity totals 122 MW.

The Owens Gorge and Owens Valley Hydroelectric Generation is a network of hydroelectric plants which use water resources of the Los Angeles Aqueduct and three creeks along the Eastern Sierras. The water flow fluctuates from year to year and as a result water flow may be reduced from seasonal norms from time to time. Since 1995, the total aqueduct exports from Owens Valley to the City have gone from approximately 476,000 acre-feet per year to currently approximately 252,000 acre-feet per year (based on the 30-year median). This difference is due to environmental uses in the Owens Valley, including Mono Lake level restoration, Lower Owens River restoration, reduced groundwater pumping and Owens Lake dust mitigation. Consequently, this water use reallocation has resulted in a reduction of downstream hydroelectric generation, which is accounted for in the annual updates of the Power System's resource plan; however, efforts are underway to reduce the amount of water required for Owens Lake dust mitigation. An estimated reduction of up to 10,000 acre-feet may be achieved depending upon terms agreed upon with applicable regulatory authorities, and may result in increased aqueduct exports from Owens Valley to the City.

San Francisquito Canyon and the Los Angeles and Franklin Reservoirs. The Department also owns and operates twelve hydroelectric units located north of the City along the Los Angeles Aqueduct in San Francisquito Canyon and at the Los Angeles and Franklin Reservoirs. The net aggregate dependable plant capacity of these smaller units is 29 MW and the net maximum capacity totals 78 MW.

Jointly-Owned Generating Units and Contracted Capacity Rights in Generating Units

The Department has additional generating resources available as capacity rights resulting from undivided ownership interests in facilities that are jointly-owned with other utilities. Also, the Department benefits from distributed generation ("DG") capacity connected to the Department's grid from customer solar photovoltaic installations through net metering and customer generation rates and from other DG units through a Feed-in-Tariff. These interests, as of May 31, 2024, are summarized in the following chart and discussed below. Each project participant with respect to jointly-owned units is generally responsible for providing its share of construction, capital, operating, decommissioning, and maintenance costs.

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JOINTLY-OWNED GENERATING UNITS AND CONTRACTED CAPACITY RIGHTS IN GENERATING UNITS

Type	Number of Facilities	Department's Net Maximum Connected Capacity (MW)	Department's Net Dependable Connected Capacity (MW)
Coal	1	1,202[(1)]	1,175
Natural Gas	1	578	483
Large Hydro	1	496[(2)]	270[(2)]
Nuclear	1	387[(3)]	380
Renewables/Distributed Generation	84,654[(4)]	3,246	1,062[(5)]
Total	**84,658**	**5,909**	**3,370**

Source: Department of Water and Power of the City of Los Angeles.

(1) The Department's IPP entitlement is 48.62% of the maximum net plant capacity of 1,800 MW. An additional 18.17% portion of the IPP entitlement is subject to variable recall as set forth under "*Intermountain Power Project – Power Recalls*" below.

(2) The Department's Hoover Power Plant contract entitlement is 496 MW, which is 23.90% of the Hoover total contingent capacity and 14.7% of the firm energy. Hoover Power Plant output constantly varies due to low water levels at Lake Mead resulting from drought conditions.

(3) The Department's PVNGS entitlement is 9.66% of the maximum net plant capacity of 4,003 MW. See "– *Palo Verde Nuclear Generating Station*" below.

(4) The Department's contract renewable resources in-service include a hydro unit in the Los Angeles area, wind farms in Oregon, Washington, Utah and Wyoming, and customer solar photovoltaic installations and other DG units located in the Los Angeles region.

(5) Figure based on statistical modeling of likely output without consideration of weather conditions that may affect the ability of certain renewable resources to reach its dependable capacity.

***Intermountain Power Project*.**

General. The IPP consists of: (i) a two-unit, coal-fired, steam-electric generating plant with a net rating of 1,800 MW (the "Intermountain Generating Station") and a switchyard (the "Switchyard"), located near Delta, in Millard County, Utah; (ii) a +500 kilovolts ("kV"), direct current transmission line approximately 490 miles in length from and including the Intermountain Converter Station (an alternating current/direct current converter station adjacent to the Switchyard) to and including a corresponding converter station at Adelanto, California (collectively, the "Southern Transmission System") (see "– Transmission and Distribution Facilities – *Southern Transmission System*"); (iii) two 50-mile, 345 kV, alternating current transmission lines from the Switchyard to the Mona Switchyard in the vicinity of Mona, Utah and a 144-mile, 230 kV, alternating current transmission line from the Switchyard to the Gonder Switchyard near Ely, Nevada (collectively, the "Northern Transmission System"); (iv) a microwave communications system; (v) a railcar service center located in Springville, in Utah County, Utah (the "Railcar Service Center"); and (vi) certain water rights and coal supplies (which water rights and coal supplies, together with the Intermountain Generating Station, the Switchyard and the Railcar Service Center, are referred to herein collectively as the "Generation Station"). Pursuant to a Construction Management and Operating Agreement between IPA and the Department, IPA appointed the Department as project manager and operating agent responsible for, among other things, administrating, operating and maintaining the IPP.

Power Contracts. Pursuant to a Power Sales Contract with IPA (the "IPP Contract"), the Department is entitled to 48.617% of the capacity of the IPP (currently equal to 875 MW). The term of the IPP Contract ends on June 15, 2027.

Pursuant to the IPP Contract, the Department is required to pay in proportion to its entitlement share the costs of producing and delivering electricity as a cost of purchased capacity. The Department also has available additional capacity in the IPP through an excess power sales agreement with certain other IPP participants (the "IPP Excess Power Sales Agreement"). Under the IPP Excess Power Sales Agreement the Department is entitled to an additional 18.168% of the capacity of IPP (currently equal to approximately 327 MW), subject to recall as described below. The IPP Contract requires the Department to pay for such capacity and energy on a "take-or-pay" basis as operating expenses of the Power System. See "OPERATING AND FINANCIAL INFORMATION – Take-or-Pay Obligations."

In Fiscal Year 2022-23, the IPP operated at a plant net capacity factor of 37.8% and provided approximately 5.9 million megawatt-hours ("MWhs") of energy to its power purchasers, which includes approximately 3.9 million MWhs to the Power System.

Intermountain Generating Station upon the termination of the IPP Contract. In order to facilitate the continued participation of the Department and other power purchasers in the IPP beyond the IPP Contract's termination in 2027, the IPA Board issued the Second Amendatory Power Sales Contract which amended the IPP Contract to allow for the repowering of the plant to replace the coal units with combined cycle natural gas units by July 1, 2025 that would allow for compliance with greenhouse gas ("GHG") emissions performance standards. Pursuant to the provisions of the power sales contracts, the IPP participants also agreed to reduce the initially planned generation capacity of the repowered plant from 1,200 MW to 840 MW. IPA released a request for proposals in June 2020 soliciting responses from developers and vendors to provide solutions for a project to supply the IPP units with green hydrogen fuel (*i.e.*, hydrogen created solely by use of renewable energy) to support the goal of operating with a blend of 30% green hydrogen starting in 2025 and the subsequent goal of reaching 100% green hydrogen fueled operation by 2045, pending the availability and the advancement of the required technology to reach those scales. The request for proposals also included proposals for hydrogen storage facilities adjacent to the existing site. An initial contract was executed in early 2022 securing energy conversion and storage services. This contract will provide the IPP participants the ability to convert renewable energy into green hydrogen to fuel the new generating units in 2025. It is estimated that the repowering of the plant to the new combined cycle units at IPP will cost approximately $1.7 billion. This estimate does not include the hydrogen facilities being constructed. Upgrades to the Switchyard and replacement of converter stations are also being undertaken at an estimated cost of approximately $2.7 billion, reflecting a change in scope requested by the Department and the cities of Burbank and Glendale to upgrade portions of the converter station to 3,000 MW. SCPPA has issued bonds to finance a portion of the costs of the upgrades to the Switchyard and converter station replacements. See "– Transmission and Distribution Facilities – *Southern Transmission System.*" See also "OPERATING AND FINANCIAL INFORMATION – Take-or-Pay Obligations."

The original power sales contracts, including the IPP Contract, will terminate on June 15, 2027, at which point the IPP Renewal Power Sales Contracts (which were executed in 2017) will immediately take operational effect and continue for a term ending in 2077. Most of the power purchasers under the original power sales contracts will continue to be IPP participants under the IPP Renewal Power Sales Contracts. The cities of Anaheim, Riverside, and Pasadena will not be power purchasers under the IPP Renewal Power Sales Contracts. The city of Burbank will take a smaller share of generation capacity under the IPP Renewal Power Sales Contracts, and the Department and the city of Glendale both increased their respective generation shares. Under its IPP Renewal Power Sales Contract with IPA, the Department will be entitled to 71.442% of the capacity of the IPP. In connection with the execution of the IPP Renewal Power Sales Contracts in 2017, the Department also executed successor excess power sales agreements with certain other IPP participants which will continue to make available to the Department additional capacity in the IPP. The increase to the Department's share and additional available capacity in the IPP will become available to the Department when the IPP Renewal Power Sales Contracts take effect on June 16, 2027. Similar to its IPP Contract, the Department will be obligated to pay for the capacity and energy purchased under its IPP Renewal Power Sales Contract on a "take-or-pay" basis as operating expenses of the Power System.

The IPA has issued bonds to finance a portion of the costs of the IPP repowering project. See "OPERATING AND FINANCIAL INFORMATION – Take-or-Pay Obligations."

Power Recalls. Under the existing IPP Excess Power Sales Agreements, certain IPP participants have a right to recall from the Department up to 18.168% of the capacity of IPP (currently equal to approximately 327 MW) for defined future summer or winter seasons or both, following no less than 90 days' notice and up to 43 MW of such capacity on a seasonal basis following no less than 90 days' notice. IPP Utah participants recalled

7.82% of the capacity of IPP (equal to 141 MW) from the Department for the summer season which started March 2024 and ended September 2024. The percentage of the capacity of IPP subject to recall will increase to 21.057% (equal to 177 MW) in 2027 upon the effectiveness of the Agreement for Sale of Renewal Excess Power which will take effect on the same day as the Renewal Power Sales Contract described above. The Department can give no assurance that the capacity of IPP subject to recall from the Department under the IPP Excess Power Sales Agreement or the Agreement for Sale of Renewal Excess Power will not be recalled in the future in accordance with the agreement terms.

Fuel Supply. IPA possesses coal supply agreements to fulfill the supply requirement of approximately 3.0 million tons in calendar year 2024 and 1.0 million tons in calendar year 2025. The coal is purchased under a portfolio of fixed price contracts that are of short and long-term in duration. However, as described below, supply chain issues resulting from the loss of coal production in the region and transportation challenges have dramatically reduced coal supply beginning in the later months of 2021 and are expected to impact coal supply for the remaining life of the coal plant. The largest coal producer in Utah experienced a fire in September 2022 and announced the closure of the mine in November 2023. The loss of the largest mine, combined with the logistics challenges in Utah, has dramatically reduced supply in the region including to IPA. As a whole, production continues to be challenging for the remaining active mines in Utah.

The recent cost of coal delivered to the Intermountain Generating Station is substantially lower than current market prices for the region. However, IPA expects that the costs to fulfill IPP's coal demand will increase due to the scarcity of coal in the Western United States if IPA is able to secure any additional coal as a replacement for the loss of sources under contract.

Transportation of coal to the Intermountain Generating Station is provided primarily by rail under agreements between IPA and the Union Pacific Railroad company. The coal is transported primarily in IPA-owned railcars. Coal is also transported to IPP, to some extent, in commercial trucks. Both rail service and trucking services have suffered greatly due to a lack of human resources. Neither network is capable of supporting industrial demand; and IPA, like all coal-fired utilities in the United States, has seen large systemic failures in the transportation system.

IPP generally maintains a minimum of 60 days of coal in inventory in the event of a coal supply disruption. At the end of May 2024, IPP maintained 106 days of coal in inventory to provide for increased generation in the summer months.

The Department has operational flexibility with respect to its use of IPP; however, the supply chain issues referenced above are likely to impact the operations of IPP and may constrain the Department's ability to utilize such resource.

For more information on the effect of certain environmental considerations on IPP and potential implications of certain recently enacted Utah legislation with respect thereto, see "FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY – *Environmental Regulation and Permitting Factors – Air Quality – Mercury*," "*– Coal Combustion Residuals*," and "*– Utah Senate Bill 161*."

Apex Power Project. The Apex Power Project (the "Apex Power Project") is located in an unincorporated area of Clark County, north of Las Vegas, Nevada. The Apex Power Project includes the Apex Generating Station, which is a combined cycle generating station consisting of one 238 MW, nameplate rating, steam turbine generator, and two simple cycle, 203 MW, nameplate rating, combustion turbine generators. The Apex Power Project also includes heat recovery equipment, air inlet filtering, closed cycle cooling system, emission control system, exhaust stack, distributed control system, all necessary noise control equipment, and its associated real property. The Apex Generating Station has a net maximum capacity of 578 MW and a net dependable capacity of 483 MW. In March 2014, SCPPA acquired the Apex Power Project for the benefit of the Department, and the Department is entitled to 100% of the capacity and energy of the Apex Power Project under a take-or-pay power sales contract with SCPPA. See "OPERATING AND FINANCIAL INFORMATION – Take-or-Pay Obligations."

Hoover Power Plant.

General. The Hoover Power Plant is located on the Arizona-Nevada border approximately 25 miles east of Las Vegas, Nevada and is part of the Hoover Dam facility at Lake Mead, which was completed in 1935 and controls the flow of the Colorado River. The Hoover Power Plant consists of 17 generating units and two service generating units with a total installed capacity of approximately 2,074 MW, and a minimum capacity of 650 MW. The Department has a power purchase agreement with the United States Department of Energy Western Area Power Administration ("Western") for 23.90% of total contingent capacity and 14.65% of the firm energy from the Hoover Power Plant through September 2067. The facility is owned and operated by the United States Bureau of Reclamation (the "Bureau of Reclamation").

Environmental Considerations. The lower Colorado River has been included in a critical Habitat Designated Area. This required the Bureau of Reclamation to prepare and file with the United States Fish and Wildlife Service (the "USFWS") a Biological Assessment on the effect of its operations of the lower Colorado River on endangered species therein (the "Biological Assessment"). After the Biological Assessment was filed, the USFWS issued a Biological and Conference Opinion regarding the Bureau of Reclamation's operations and outlined remedial actions to be taken to correct adverse effects to endangered species. Such remedial actions could affect the operation of the Hoover Power Plant, which would in turn affect the Hoover Power Plant customers, including the Department. The Department believes that any impact of the Biological and Conference Opinion on future operations will be minor; however, there is a possibility that future regulatory action will recommend major remediation actions that could have a material impact on the Hoover Power Plant customers' available capacity from the Hoover Power Plant. The Hoover Power Plant customers, including the Department, together with certain other parties, have implemented a plan in cooperation with the Bureau of Reclamation and the USFWS to mitigate negative effects on the Hoover Power Plant's energy production.

Palo Verde Nuclear Generating Station.

General. PVNGS is located approximately 50 miles west of Phoenix, Arizona. PVNGS consists of three nuclear electric generating units (numbered 1, 2 and 3), with a net maximum capacity of 1,333 MW (unit 1), 1,336 MW (unit 2) and 1,334 MW (unit 3) and a dependable capacity of 1,311 MW (unit 1), 1,314 MW (unit 2) and 1,312 MW (unit 3). PVNGS's combined design capacity is 4,003 MW and its combined dependable capacity is 3,937 MW. Each PVNGS generating unit has been operating under 40-year Full-Power Operating Licenses granted by the Nuclear Regulatory Commission (the "NRC") expiring in 2025, 2026, and 2027, respectively. In April 2011, the NRC approved PVNGS's license renewal application, allowing the three units to extend operation for an additional 20 years until 2045, 2046 and 2047, respectively.

Arizona Public Service Company ("APS") is the operating agent for PVNGS. On average, PVNGS has provided over 3.1 million MWhs of energy annually to the Power System. The Department has a 5.7% direct ownership interest in the PVNGS (approximately 224 MW of dependable capacity). The Department also has a 67.0% generation entitlement interest in the 5.91% ownership share of PVNGS that belongs to SCPPA through its "take-or-pay" power contract with SCPPA (totaling approximately 156 MW of dependable capacity), so that the Department has a total interest of approximately 380 MW of dependable capacity from PVNGS. Co-owners of PVNGS include APS; the Salt River Project; Edison; El Paso Electric Company; Public Service Company of New Mexico; SCPPA and the Department.

Nuclear Regulatory Commission. The NRC has broad authority under federal law to impose licensing and safety-related requirements for the operation of nuclear generation facilities. Events at nuclear facilities of other operators or impacting the industry generally may lead the NRC to impose additional requirements and regulations on existing and new facilities.

The aftermath of the March 2011 earthquake and tsunami that caused significant damage to the Fukushima Daiichi Nuclear Power Plant in Japan prompted the U.S. nuclear industry to form a task force under the direction of PVNGS's Chief Nuclear Officer to take immediate actions in ensuring the reliability of all U.S. nuclear plants. PVNGS instituted improvements driven by the findings from such task force. Among these improvements, is a staging of “flex” equipment, which includes mobile pumps, generators, hoses, and fire trucks that enable PVNGS to shift cooling water through the plant and power critical equipment in the event of a disaster.

Decommissioning Costs. The owners of PVNGS have created external trusts in accordance with the PVNGS participation agreement and NRC requirements to fund the costs of decommissioning PVNGS. Based on the 2023 annual funding status report which is based on a 2019 study of decommissioning costs, the most recent estimate available, the Department estimates that its share of the amount required for decommissioning PVNGS relating to the Department’s direct ownership interest in PVNGS was approximately 73% funded and that its share of decommissioning costs through SCPPA was 84% funded. The Department’s direct share of costs is $204.9 million and SCPPA’s share is $222.0 million, of which the Department’s portion is $148.7 million or 67%. Under the current funding plan, the Department estimates its share of the decommissioning costs relating to the Department’s direct ownership interest in PVNGS will be fully funded by accumulated interest earnings and additional contributions by the extended license expiration date of 2047. Such estimates assume 7% per annum in future investment returns and a 5% per annum cost escalation factor. The Department has received and is receiving less than a 7% per annum investment return on the decommissioning funds and cost increases have been averaging less than 5% per annum. No assurance or guarantee can be given that investment earnings will fully fund the Department’s remaining decommissioning obligations at current estimated costs or that the decommissioning costs will not exceed current estimates. For a discussion of the Department’s nuclear decommissioning trust fund and other investments held on behalf of the Department, see “THE DEPARTMENT OF WATER AND POWER OF THE CITY OF LOS ANGELES– Investment Policy and Controls.”

Nuclear Waste Storage and Disposal. Generally, federal and state efforts to provide adequate interim and long-term storage facilities for low-level and high-level nuclear waste have proven unsuccessful to date. Although federal and state efforts continue with respect to such storage and disposal facilities, the Department is not able to predict the schedule for the permanent disposal of radioactive wastes generated at PVNGS. Since the spent fuel pools ran out of storage capacity, an independent spent fuel storage installation was built to provide additional spent fuel storage at the site while awaiting permanent disposal at a federally developed facility. The installation uses dry cask storage and was designed to accept all spent fuel generated by PVNGS during its lifetime. As of December 31, 2023, 152 casks, each containing 24 spent fuel assemblies, and 24 new casks, each containing 37 spent fuel assemblies allowing the dry cask storage facility to accept more spent fuel at a time, have been stored. Storage costs are partially paid using funds received by APS pursuant to a settlement agreement with the United States government relating to nuclear waste disposal fees.

Mohave Generating Station – Operations Ceased. The Mohave Generating Station was a coal-fired electric generating station located near Laughlin, Nevada, that ceased operations in 2005. The Department owned a 30% interest in the Mohave Generating Station and still owns a 30% interest in the site. The other co-owners are Edison and NV Energy (formerly known as Nevada Power Company). The Mohave Generating Station generating units were removed from service at the end of 2005. A major plant decommissioning was completed in 2012. As required by the Nevada Division of Environmental Protection, minor cleanup, ground water monitoring and upkeep of the plant site will continue for a number of years after the decommissioning to ensure that the integrity of the coal ash landfill is maintained and that the groundwater is protected from contamination. In accordance with an approved site disposition plan, the co-owners of the Mohave Generating Station have made approximately 80% of the property of the Mohave Generating Station available for public sale. Any sales transaction will require approval from the Board and City Council. The remaining property would be retained by the co-owners for ongoing monitoring, maintenance, and environmental compliance purposes. See “FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY – *Environmental Regulation and Permitting Factors – Coal Combustion Residuals.*”

Navajo Generating Station – Operations Ceased. The Navajo Generating Station was a coal-fired, electric generating station located near the City of Page, Arizona, that ceased operations in 2019. The Salt River Project Agricultural Improvement and Power District, a political subdivision of the state of Arizona, and the Salt River Valley Water Users’ Association, a corporation (together, the “Salt River Project”) is the operating agent of the Navajo Generating Station. The Department sold its interest in the Navajo Generating Station in 2016, however the Department is still responsible for its portion of decommissioning costs.

LA100 Study

In accordance with three City Council motions passed in 2016 and 2017, the Department partnered with the NREL to perform the "LA100: The Los Angeles 100% Renewable Energy Study" (the "LA100 Study"). This unprecedented, three-year study identified several pathways that would allow the City to achieve a 100%-renewable-energy portfolio no later than 2045. The NREL identified four overall scenarios with various modeling assumptions for the Department to achieve its sustainability goals, including one scenario to achieve its goals by 2035. The NREL also analyzed how the scenarios could affect the region's air quality, GHG emissions, public health, jobs, and economic activity. At the direction of the City Council, the study incorporated the CalEnviroScreen, allowing the NREL to identify pathways that will be not only economical for the utility but also equitable for communities.

The LA100 Study yielded a tremendous amount of data and new, state-of-the-art models that provide the Department with a variety of perspectives on approaches toward 100% renewable energy. The results of the LA100 Study will continue to inform the Department's internal planning processes, including its Strategic Long-Term Resource Plan and other public outreach efforts that are designed to ensure a just and equitable transition for the City. The Financial Services Organization of the Department has conducted a preliminary rate analysis to determine the rate impacts for each of the scenarios in the LA100 Study. However, more in-depth analysis on the specific path is needed to ascertain more accurate rate analysis. The total cumulative cost through 2045 of new investment needed to achieve the suite of modeled scenarios ranges from approximately $57 billion to $87 billion, depending on the scenario, load projection, and the target year.

At the conclusion of the LA100 Study, it was determined that the LA100 Study provided various ways to reach 100% clean energy but it did not fully address the topic of equity as part of the transition. As a result, the LA100 Equity Strategies Study was commissioned by the Board. The independent study was conducted by the NREL and by UCLA with focused research in five priority areas: (1) affordability and energy burdens; (2) access to and use of energy technologies, programs, and infrastructure; (3) health, safety, and community resilience; (4) jobs and workforce development; and (5) inclusive community involvement. The ultimate goal of the LA100 Equity Strategies Study is for all communities across the City to share in the benefits and the burdens of the clean energy transition and to identify what policies should be put in place to achieve such outcomes. The LA100 Equity Strategies study report was released in November 2023. The report details a number of findings, recommendations and strategies addressing inequities in the clean-energy transition and is designed to assist the Department to make data-driven, community-informed decisions for equitable investment and program development towards achieving a 100% carbon-free energy portfolio. See also "–Renewable Power Initiatives – *L.A.'s Green New Deal*" and – *Strategic Long-Term Resource Plan*."

Renewable Power Initiatives

The Department expects to continue to procure a renewable power resource portfolio that satisfies applicable State requirements, the main provisions of which are currently contained in the California Renewable Energy Resources Act ("SBX 1-2"), the California Global Warming Solutions Act of 2006 ("AB 32" or the "Global Warming Solutions Act"), the Clean Energy and Pollution Reduction Act of 2015 ("SB 350"), and the 100 Percent Clean Energy Act of 2018 ("SB 100"). For a discussion of certain State legislation and regulations affecting the Department, including AB 32, SB 350, SB 1368, SBX 1-2, SB 100, and the Clean Energy, Jobs, and Affordability Act of 2022 ("SB 1020"), see "FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY – California Climate Change Policy Developments." Certain components of the Department's renewable power resource portfolio are described below. Available capacity with respect to such renewable power resources will vary as they are intermittent resources. Wind power, both obtained through power purchase agreements and resources owned by the Department, provided 11% and 13% of the Department's energy in 2021 and 2022, respectively, or about one-third of the renewable energy, which comprised 35% and 36% of the total energy mix in 2021 and 2022, respectively, as reflected in the Department's Annual Power Content Label for such years.

Large Scale Wind Energy. Through power purchase agreements, the Department has secured large scale wind farm output in a number of areas to provide a diversity of wind power resources. Such wind energy for the Department is being generated in wind farms located in the States of California, Oregon, Washington, Utah, and Wyoming, and New Mexico. Such power purchase agreements provide for an aggregate of 1,143 MW of wind energy. In addition to these power purchase agreements, wind farms with output of approximately 880 MW are also subject to Department options to purchase such assets.

Certain of these projects are described as follows:

Milford Wind Corridor Phase I Project. The Milford Wind Corridor Phase I Project (the "Milford I Project") began commercial operation in November 2009 and consists of SCPPA's purchase of all energy generated by a 203.5 MW nameplate capacity wind farm comprised of 97 wind turbines located near Milford, Utah (the "Milford I Facility"), for a term expiring in November 2029 (unless earlier terminated) pursuant to a Power Purchase Agreement, by and between SCPPA and Milford Wind Corridor Phase I, LLC. Energy from the Milford I Facility is delivered to SCPPA over an approximately 90-mile, 345 kV transmission line extending from the wind generation site to the IPP Switchyard in Delta, Utah. SCPPA has issued revenue bonds in order to finance the purchase by prepayment of 6,764,301 MWhs of energy from the Milford I Facility over the delivery term. The Department has entered into a power sales agreement with SCPPA that provides for the Department to pay for its 92.5% share of the Milford I Project on a "take-or-pay" basis as an operating expense of the Power System. See "OPERATING AND FINANCIAL INFORMATION – Take-or-Pay Obligations."

Milford Wind Corridor Phase II Project. The Milford Wind Corridor Phase II Project (the "Milford II Project") began commercial operation in May 2011 and consists of SCPPA's purchase of all energy generated by a 102 MW nameplate capacity wind farm comprised of 68 wind turbines located near Milford, Utah (the "Milford II Facility"), for a term expiring on June 30, 2031 (unless earlier terminated) pursuant to a Power Purchase Agreement, by and between SCPPA and Milford Wind Corridor Phase II, LLC. Energy from the Milford II Facility is delivered to SCPPA over an approximately 88-mile, 345 kV transmission line extending from the wind generation site to the IPP Switchyard in Delta, Utah. SCPPA has issued revenue bonds in order to finance the purchase by prepayment of 4,467,600 MWhs of energy from the Milford II Facility over the delivery term. In connection with the issuance of bonds relating to the Milford II Project, the Department has entered into a power sales agreement with SCPPA that provides for the Department to pay for its 95.098% share of the Milford II Project on a "take-or-pay" basis as an operating expense of the Power System. In addition, the Department has purchased the City of Glendale's 4.902% output entitlement share of Milford II Project's output. See "OPERATING AND FINANCIAL INFORMATION – Take-or-Pay Obligations."

Linden Wind Energy Project. The Linden Wind Energy Project (the "Linden Project") began commercial operation in June 2010 and consists of SCPPA's acquisition of a 50 MW nameplate capacity wind farm comprised of 25 wind turbines located near the town of Goldendale in Klickitat County, Washington. The Linden Project was developed and constructed by Northwest Wind Partners, LLC ("Northwest Wind"). SCPPA acquired the project from Northwest Wind pursuant to the terms of an asset purchase agreement between SCPPA and Northwest Wind. Energy from the Linden Project is delivered to SCPPA through an energy exchange agreement that redelivers production from the Linden Project to the Pacific DC Intertie. SCPPA has issued revenue bonds to finance the acquisition of the Linden Project. The Department has entered into a power sales agreement with SCPPA for a term expiring in 2035 (unless earlier terminated) that provides for the Department to pay its 90.00% share of the Linden Project on a "take-or-pay" basis as an operating expense of the Power System. In addition, the Department has purchased the City of Glendale's 10.00% output entitlement share of the Linden Project's output. See "OPERATING AND FINANCIAL INFORMATION – Take-or-Pay Obligations."

Windy Point/Windy Flats Project. The Windy Point/Windy Flats Project began commercial operation in January 2010 and is a 262.2 MW nameplate capacity wind farm comprised of 114 wind turbines located in the Columbia Hills area of Klickitat County, Washington near the city of Goldendale (the "Windy Point Project"). The Windy Point Project is owned and operated by Windy Flats Partners, LLC ("Windy Flats"). Pursuant to a power purchase agreement with Windy Flats, SCPPA has agreed to purchase from Windy Flats all energy from the Windy Point Project for a delivery term that was originally expiring in 2030 (unless earlier terminated). In March 2023, an amendment to the original power purchase agreement was approved which extended the delivery term for an additional four years, to 2034. Energy from the Windy Point Project is delivered to SCPPA through an energy exchange agreement that redelivers production from the Windy Point Project to the Pacific DC Intertie. SCPPA has issued revenue bonds to finance the prepayment of the purchase of 11,107,860 MWhs of energy from the Windy Point Project. The Department has entered into a power sales agreement with SCPPA that provides for the Department to pay its 92.37% share of the Windy Point Project on a "take-or-pay" basis as an operating expense of the Power System. In addition, the Department has purchased the City of Glendale's 7.63% output entitlement share of Windy Point Project's output. See "OPERATING AND FINANCIAL INFORMATION – Take-or-Pay Obligations."

Pine Tree Wind Project. The Pine Tree Wind Project (the "Pine Tree Wind Project") is a wind generating facility north of Mojave, California, consisting of 90 wind turbines owned and operated by the Department. The Pine Tree Wind Project began commercial operation in June 2010 and has a nameplate capacity of 135 MW. As part of normal operating procedures, the Department staff has notified federal and State authorities concerning mortalities of golden eagles. Since June 2009, the Department staff has found nine golden eagle carcasses in the proximity of the Pine Tree Wind Project. The Department has completed advanced monitoring studies and surveys to research golden eagle behavior within the vicinity of the Pine Tree Wind Project and to determine potential causes of the eagle mortalities and mitigation options relating to the golden eagles. The Department previously conducted tests using radar and automated deterrent technology in detecting and deterring golden eagles and other birds of prey at the Pine Tree Wind Project. Golden eagles are a protected species, and the death or injury to a golden eagle in some circumstances can result in fines and penalties, including criminal sanctions. As of June 2017, the Department entered into a settlement agreement with the USFWS to address the golden eagle mortalities at the Pine Tree Wind Project. The Department completed its golden eagle research and development study as required by the settlement agreement and submitted the final summary report to USFWS in September 2020. On December 29, 2020, the Department received a letter from the USFWS indicating that the Department had fulfilled the terms of the settlement agreement with respect to the research and development study, payment, and meet and confer with USFWS staff. The Department is still coordinating with the USFWS to obtain an incidental take permit for golden eagles as a separate requirement under the settlement agreement. In order to protect condors, a protected species under State and federal law, the Department has implemented a condor detection protocol that includes turbine curtailment when condors are observed in the immediate area. Additionally, the Department has prepared a condor conservation plan and obtained an incidental take permit for California condors on November 28, 2023. The condor conservation plan outlines the avoidance measures that are currently being implemented and the proposed compensatory mitigation measures in an effort to protect and address the declining condor population.

Red Cloud Wind Project. In November 2020, the Department entered into a power sales agreement with SCPPA to purchase renewable energy purchased by SCPPA from the Red Cloud Wind Project located in New Mexico (the "Red Cloud Wind Project"). Pursuant to a power purchase agreement with Red Cloud Wind, LLC, SCPPA purchases 331 MW of renewable energy to be delivered to the Department at the Navajo 500 kV Switching Station for a 20-year term. The Red Cloud Wind Project was developed by Pattern Energy and commenced commercial operation on December 22, 2021. The Red Cloud Wind Project is expected to deliver an annual average of approximately 1,333,000 MWhs of renewable energy to the Department.

Distributed Energy Resource Programs. The Department has implemented the following programs to encourage the development of solar energy in Los Angeles: (i) the Solar Incentive Program in which residential and commercial customers are encouraged to install eligible solar photovoltaic systems with incentive funding provided by the Department, which ended in December 2018; (ii) Department-built solar projects on City-owned properties; (iii) the Solar Rooftops Program, which places Department-owned solar panels on qualifying residential rooftops in exchange for predefined lease payments to the customer; (iv) a Feed-in-Tariff ("FiT") program, launched on February 1, 2013, which has a total installed capacity of 110.7 MW comprised of 4 MW of solar photovoltaic generation in the Owens Valley and 4 MW of renewable landfill gas generation, and 102.7 MW of photovoltaic generation installed within the Department's in-basin service territory and connected to the Department's electric distribution system; (v) the Shared Solar Program ("SSP"), which enables residential customers living in multi-family dwellings to fix the pricing of a portion of their electric bills based upon the costs and benefits of Department solar installations; (vi) the Virtual Net Energy Metering ("VNEM") pilot program, which launched in March 2021 and allows developers or building owners to install solar arrays on multi-family dwelling unit buildings and split the energy sales proceeds with tenants; and (vii) the FiT Plus program, which facilitates the installation of energy storage with existing and new FiT photovoltaic projects.

Under the California Solar Initiative ("SB-1"), POUs are required to establish programs supporting the stated goal of the legislation to install 3,000 MW of photovoltaic capacity in the State, and to establish eligibility criteria in collaboration with the CEC for the funding of solar energy systems receiving ratepayer funded incentives. The Solar Incentive Program used $339 million of ratepayer funds mandated by SB-1 to administer the program and subsidize customers for customer-owned solar projects to offset their electricity use. As of December 2018, the Department committed all funds available for this program for 279.7 MW of installations.

The Department currently has 25.9 MW of Department–built solar projects on City-owned properties. The Adelanto Solar Power Project is a 10 MW solar photovoltaic system placed into commercial operation in June 2012, which is expected to deliver 450,000 MWhs of energy over 25 years, located at the existing Adelanto Switching and Converter Station near Adelanto, California. In addition, the Pine Tree Solar Project was placed into commercial operation in March 2013. The Pine Tree Solar Project is an 8.5 MW solar photovoltaic system expected to deliver 350,000 MWhs of energy over 25 years, located at the Department's existing Pine Tree Wind Project in the Tehachapi Mountains, California. The remaining 6.9 MW includes installations spread across various City owned properties in the Los Angeles Basin as well as a 500kW system in the Owens Valley.

The Department has entered into the following 13 power purchase agreements ("PPAs") for the purchase of renewable energy from 1,495 MW of solar photovoltaic projects:

- One PPA with an option to purchase is a 25-year contract with K Road Moapa Solar, LLC, which changed its name to Moapa Southern Paiute Solar, LLC, for 250 MW, delivering up to 618,000 MWhs a year to the Department. The solar facility is located on Moapa Band of Paiute Indians tribal land north of Las Vegas, Nevada. The Department acquired the approximately 5.5-mile transmission line associated with the facility, which achieved full commercial operation in December 2016.

- The second PPA with an option to purchase is a 20-year contract through SCPPA for 210 MW of the Copper Mountain Solar 3 Project developed by an affiliate of Sempra U.S. Gas and Power. Copper Mountain Solar 3 Project is near Boulder City, Nevada and is expected to deliver 515,000 MWhs of renewable energy a year to the Department and began full commercial operation in April 2015.

- The third PPA with an option to purchase is a 20-year contract for 60 MW of the RE Cinco Solar Project developed by Recurrent Energy, an affiliate of Canadian Solar Inc. RE Cinco Solar Project is near the Mojave Desert in Kern County and is expected to deliver an annual average of 182,000 MWhs of renewable energy a year to the Department. This facility began full commercial operation in August 2016.

- The fourth PPA with an option to purchase is a 25-year contract through SCPPA for 105 MW of the Springbok I Solar Farm Project developed by Avantus LLC (formerly 8Minutenergy). Springbok I Solar Farm Project is near the Mojave Desert in Kern County and is expected to deliver an average of 284,000 MWhs of renewable energy a year to the Department. This facility began full commercial operation in July 2016.

- The fifth PPA with an option to purchase is a 27-year contract through SCPPA for 155 MW of the Springbok II Solar Farm Project, which is adjacent to the Springbok I Solar Farm Project and was developed by Avantus LLC. Springbok II Solar Farm Project is expected to deliver an average of 420,000 MWhs of renewable energy a year to the Department. This facility began full commercial operation in September 2016.

- The sixth PPA with an option to purchase is a 27-year contract through SCPPA for 90 MW of the Springbok III Solar Farm Project, which is adjacent to the Springbok I and Springbok II Solar Farm Projects and was developed by Avantus LLC. Springbok III Solar Farm Project is expected to deliver an average of 240,000 MWhs of renewable energy a year to the Department. This facility began full commercial operation in July 2019.

- The seventh PPA with an option to purchase, named the Eland Solar & Storage Center, Phase 1, is a 25-year contract through SCPPA for 175 MW of energy and 131.25 MW/525 MWhs of battery energy storage. The Eland Solar & Storage Center, Phase 1 is located in the Barren Ridge area adjacent to the Eland Solar & Storage Center, Phase 2, and is being developed by Arevon Energy, Inc., with commercial operation expected before the end of calendar year 2024. Eland Solar & Storage Center, Phase 1 is expected to deliver an average of approximately 702,000 MWhs of renewable energy a year to the Department.

- The eighth PPA with an option to purchase, named the Eland Solar & Storage Center, Phase 2, is a 25-year contract through SCPPA for 200 MW of energy and 150 MW/600 MWhs of battery energy storage. The Eland Solar & Storage Center, Phase 2 is located in the Barren Ridge area adjacent to the Eland Solar & Storage Center, Phase 1, and is being developed by Arevon Energy, Inc., with commercial operation expected in the first quarter of calendar year 2025. Eland Solar & Storage Center, Phase 2 is expected to deliver an average of approximately 803,000 MWhs of renewable energy a year to the Department.

- The ninth through thirteenth PPAs are related to the Beacon Solar Project Sites 1 thru 5. The Beacon Property, located in the Mojave Desert near the Pine Tree Wind Project, is a 2,500-acre property purchased by the Department from Nextera Energy Resources in 2012. Five PPAs and associated agreements have been executed for the development of five solar sites totaling 250 MW within the Beacon Property. Each of the five solar sites achieved commercial operation at different dates within the years 2016 and 2017, and are expected to generate an average of 581,000 MWhs per year of solar energy in aggregate over a term of 25 years. The PPAs provide the Department with an option to purchase the solar projects after the developers have realized the federal tax benefits.

In connection with the implementation of these PPAs, the Department has upgraded certain transmission assets to accommodate these projects in the Barren Ridge area. See "– Transmission and Distribution Facilities – *Barren Ridge Renewable Transmission Project*."

The Department's 450 MW FiT program allows the Department to purchase, through power purchase contracts, electricity generated from program participants' renewable energy generating sources. Such sources are to be located within the Department's service territory and connected to the Power System. The energy purchased through the FiT program is expected to count toward the Department's RPS targets. As discussed above, as part of the PPAs for solar development on the Beacon Property, the Beacon Solar developers installed additional solar in the Department's service territory. The Department has allocated the capacity of the original 150 MW FiT program. The Department obtained approval from the City Council to expand the FiT program by an additional 300 MW of capacity. The first 50 MW offering of this expansion was authorized in January 2020. In addition to increasing the FiT program from 150 MW to 450 MW over a number of years, the FiT program will now accommodate all renewable technologies approved by the CEC and expand each project's maximum capacity, previously set at 3 MW, to 10 MW. The FiT Plus and VNEM pilot programs will use 10 MW and 5

MW of the existing FiT capacity, respectively. The FiT Plus pilot program encourages the installation of battery energy storage with local solar projects, making solar energy dispatchable, while increasing the power grid's reliability and resiliency. The VNEM pilot program facilitates the installation of solar projects on multifamily dwellings and allows renters to readily access the benefit of these systems. In April 2023, the Board approved the use of an additional 75 MW of capacity for the FiT programs and the Department introduced a FiT Carport and Canopy Incentive program. Out of the 450 MW authorized by City Council, the use of a total of 275 MW has been approved across all FiT programs.

Geothermal Development. The Department executed a power sales agreement with SCPPA for 84.62% of the energy output, or 114 GWhs annually, of the Don A. Campbell Phase I Geothermal Energy Project (the "Don Campbell Phase I Project"), which began commercial operation on January 1, 2014. The Don Campbell Phase I Project consists of SCPPA's purchase of all energy generated by a 16.2 MW nameplate capacity binary geothermal power plant comprised of eight drilled commercial wells located in Mineral County, Nevada for an initial delivery term of 20 years expiring December 31, 2033.

In addition, in April 2015, the Department executed a power sales agreement with SCPPA for 100% of the energy output, or 135 GWhs annually, of the Don A. Campbell Phase II Geothermal Energy Project (the "Don Campbell Phase II Project" and, together with the Don Campbell Phase I Project, the "Don Campbell Projects"), which expires in September 2035 and is located in the same vicinity as the Don Campbell Phase I Project. The Don Campbell Phase II Project is an expansion of the Don Campbell Phase I Project by the same developer, Ormat Nevada, Inc., and began commercial operation in September 2015. The nameplate capacity for the Don Campbell Phase II Project is 16.2 MW.

In addition to the Don Campbell Projects, the Department executed a power sales agreement with SCPPA in September 2013 for a share of the output purchased by SCPPA from the Heber-1 Geothermal Project (the "Heber-1 Project"). The energy delivery commencement date was February 2, 2016 for an initial term of ten years. The Heber-1 Project is an existing geothermal complex which includes the Heber-1 double flash steam unit and the Gould 1 bottoming binary unit, located in Imperial County, California. The net energy generated from the Heber-1 Project is expected to be 46 MW. The Department's share was 66.67% (30.68 MW) in the first three years and is 78.0% (35.88 MW) for the remaining term. The equivalent average energy delivered to the Department is expected to be 285 GWhs annually.

In addition, the Department executed a power sales agreement with SCPPA in December 2016 for a share of the output purchased by SCPPA from the Ormesa Geothermal Complex Project (the "Ormesa Project"). The energy delivery commencement date was January 1, 2018 for a term of 25 years, ending on December 31, 2042. Similar to the Heber-1 Project, the Ormesa Project is an existing geothermal complex which includes two active binary units and one active bottoming unit, located in Imperial County, California. The generation capacity of the project is 35 MW. The Department's share is 85.71% (30 MW) of the energy output. The equivalent average energy delivered to the Department is expected to be 250 GWhs annually.

In May 2017, the City Council approved a power sales agreement with SCPPA for 100% of the output purchased by SCPPA from the Ormat Northern Nevada Geothermal Portfolio Project. At full service, this project provides the Department with approximately 163.54 MW of renewable geothermal energy from six power plants in various locations in Nevada. This amount is expected to represent approximately 5% of the Department's renewable energy portfolio in 2030. Energy delivery from the project stepped up in three phases from December 31, 2017 to December 31, 2022 as follows: 60 MW minimum and 85 MW maximum by December 31, 2018 (which was achieved), cumulative 90 MW minimum and 130 MW maximum by December 31, 2020 (which was achieved), and cumulative 135 MW minimum and 185 MW maximum by December 31, 2022 (which was achieved). The maximum annual energy received by the Power System from the project is expected to be approximately 1,620 GWhs. The power sales agreement with SCPPA expires in December 2043.

Biomass Development. In March 2018, the City Council approved a power purchase agreement with SCPPA for a share of the output of the ARP-Loyalton Biomass Project in Sierra County, California, which began commercial operation in April 2018. SCPPA partnered with other State POUs to purchase a total of 18 MW of capacity for a term of five years towards satisfaction of procurement obligations under SB 859. The Department's share of the ARP-Loyalton Biomass Project was 8.9 MW. Following the bankruptcy of the operator and its parent company, energy deliveries from the ARP-Loyalton Biomass Project ceased in February 2020 and did not resume. The power purchase agreement for the output of the project expired by its terms on April 19, 2023. The Department has also contracted with SCPPA to purchase 5.4 MW of rated capacity from the Roseburg SB 859 biomass project. These two power purchase arrangements allow the Department to meet its requirement to purchase 14.3 MW of rated capacity from biomass sourced energy facilities in order to comply with SB 859. See "FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY – California Climate Change Policy Developments – *Biomass Legislation*."

Energy Storage Development. In connection with the implementation of State law, the Department is developing viable and cost-effective energy storage systems. The goals of the energy storage systems include reducing emissions of GHGs, reducing demand for peak dispatchable generation and improving the reliability of the electric grid. Although energy storage systems themselves are not considered renewable resources, they facilitate the integration of renewable resources into the Power System. To date, the Department has implemented several small energy storage systems throughout the Power System, including:

- The 12 kW Fire Station 28 Battery Energy Storage System (BESS), located near the Porter Ranch area, commenced operation in October 2017.

- The 60 kW Lithium-Ion BESS, located at the Department's La Kretz Innovation Center, was integrated into the existing solar panel system in 2016.

- The 55 kW Lithium-Ion BESS, located at the Department's Truesdale Training Center, was commissioned in 2017.

- The 20 MW Beacon utility-scale BESS project, located on the Beacon Property, which commenced operation in October 2018.

- The 1.5 MW Lithium-Ion BESS, located at the Springbok 3 solar plant, installed in October 2019 for technical and operational performance demonstrations.

- The 100 kW Lithium-Ion BESS and 100 kW Flow BESS, located at the Department's headquarters (John Ferraro Building), which commenced operation in November 2019.

In addition, as discussed above, in 2020, the Department entered into PPAs for energy storage systems at the Eland Solar & Storage Center, Phase 1 and the Eland Solar & Storage Center, Phase 2. Phase 1 is expected to be commissioned in 2024 and Phase 2 is expected to be commissioned in 2025.

See "FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY – California Climate Change Policy Developments – *Energy Storage Legislation*."

The Department issued a Standalone Energy Storage RFP, through SCPPA, for various technologies, including Long Duration Energy Storage (LDES). Following review of the proposals received, the Department will begin negotiations with the vendor(s) that meets the Department's requirements.

Green Power Program. The Department offers its Green Power Program to all customers at a premium over standard rates. "Green Power" is produced from renewable resources such as solar and wind energy, rather than fossil-fueled or nuclear generating plants. This voluntary program includes customer-selected levels of Green Power purchases, subject to specified minimum requirements. Approximately 9,124 Department customers subscribed to the Green Power Program as of December 2023.

Other Renewable Energy Project Developments. The Department, on its own and through SCPPA, has received proposals from renewable energy resources such as solar photovoltaic, wind, biomass, small hydro, solar thermal and geothermal power via solicitations. The Department is also considering opportunities related to utilization of land located in the Owens Valley area of the State for solar, wind or geothermal and for improved transmission access to geothermal energy. In addition, as part of then Mayor Eric Garcetti's announcement in February 2019 that certain natural gas units will be phased out and replaced with renewable energy producing assets, the Department will be exploring options over the next few years to develop such assets for the Power System. See "THE POWER SYSTEM – Department Owned Facilities – *Once-Through-Cooling Units Phase-Out*" for more information. Additional renewable energy resources will be obtained; however, the Department's participation in or acquisition of any specific renewable energy project will be subject to City Council approval when required, and the costs and schedules for implementation and feasibility of any such alternative energy projects may vary materially from initial projections.

L.A.'s Green New Deal. On February 10, 2020, then Mayor Eric Garcetti released his Executive Directive No. 25 implementing L.A.'s Green New Deal. As part of this directive, the City expects the Department to provide equitable access to clean energy programs, build zero carbon microgrids in City owned infrastructure, deploy smart meters City-wide and institute other similar initiatives. The Department is studying how to implement this directive and other renewable power related directives and the effect they will have on the finances and operations of the Power System.

On April 19, 2021, then Mayor Eric Garcetti declared in his 2021 Los Angeles State of the City address his goal for the Department to provide an energy mix that is 80% renewable and 97% GHG-free resources by 2030, a full six years ahead of the L.A. Green New Deal, and to use the LA100 Study as a guide to fulfill President Biden's energy vision, with a goal of 100% carbon-free energy by 2035. To achieve these goals, the then Mayor referenced the Department's transition of Scattergood Generating Station to clean energy alternatives, the construction of the Red Cloud Wind Project in New Mexico, the partnership with the Navajo Nation for solar energy, and the supply of IPP with green hydrogen fuel. For more information on the LA100 Study, see "THE POWER SYSTEM – *LA100 Study*." For more information on the transition of Scattergood Generating Station, see "FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY – Environmental Regulation and Permitting Factors – Water Quality – Cooling Water Process – State Water Resources Control Board." For more information on the Red Cloud Wind Project, see "THE POWER SYSTEM – Renewable Power Initiatives – *Red Cloud Wind Project*." For more information on the Navajo Project, see "THE POWER SYSTEM – Jointly-Owned Generating Units and Contracted Capacity Rights in Generating Units - *Navajo Generating Station – Operations Ceased*." For more information on the re-powering of IPP, see "THE POWER SYSTEM – Jointly-Owned Generating Units and Contracted Capacity Rights in Generating Units – *Intermountain Power Project – Intermountain Generating Station upon the termination of the IPP Contract*."

The Clean Grid LA Plan Update was presented to the Board on May 11, 2021. The Clean Grid LA Plan Update is a 10-year roadmap that aligns with the LA100 Study to assist the Department with its clean energy goals. Elements of the Clean Grid LA Plan include providing 80% renewable and 97% GHG-free resources by 2030, accelerating transmission projects, transforming local generation, accelerating energy storage, and deploying distributed energy resources equitably. The Department plans to construct a combined cycle generating system capable of utilizing green hydrogen at Scattergood Generating Station which is expected to be in-service by 2029. Moreover, the Department continues to assess the potential opportunities for additional green hydrogen-fueled electricity generation across the coastal, in-basin generating stations. In addition to the Scattergood Green Hydrogen-Ready Modernization Project, the Department plans to convert Haynes Unit 8 from once-through cooling to wet cooling by 2027.

To fully understand the opportunities for developing a comprehensive green hydrogen economy in California, the Department is engaged with the Alliance for Renewable Clean Hydrogen Energy Systems ("ARCHES"). ARCHES is a public-private partnership led by the California Governor's Office of Business and Economic Development (GO-Biz) that is seeking to secure and maximize federal, state, and private funding for a California hydrogen hub. Most significantly, ARCHES is seeking federal funding through the federal

Department of Energy's Regional Clean Hydrogen Hubs program which includes up to $7 billion to establish no more than 10 regional hydrogen hubs across the country. Through the ARCHES framework, the Department is collaborating with partners across the region and advocating for the development of local green hydrogen economy.

On May 19, 2022, the City Council voted to instruct the Department and the Port of Los Angeles ("POLA") to coordinate a local effort to create and submit a proposal to the Department of Energy proposing the Greater Los Angeles area for consideration as a regional green hydrogen hub. Through ARCHES, the Department and its partners submitted an application that details a proposed clean hydrogen ecosystem in California comprised of new and existing projects. On October 13, 2023, President Biden and Energy Secretary Jennifer Granholm announced $7 billion in awards for seven regional clean hydrogen hubs, of which the California-centered hub will receive $1.2 billion. The Department continues to work with both public and private entities to develop the necessary partnerships and governance structures, conduct market and system value benefit studies, and gather stakeholder feedback. The development and outcomes from this effort will be foundational to the Department's decarbonization efforts at the Los Angeles Basin Stations.

Strategic Long-Term Resource Plan. On September 1, 2021, the City Council voted to instruct the Department to "prepare a Strategic Long-Term Resource Plan that achieves 100% carbon-free energy by 2035, in way that is equitable and has minimal adverse impact on ratepayers." In addition, the City Council instructed the Department to "create a long term hiring and workforce plan . . . ensuring project labor agreements, [payment of] prevailing wage[s] . . . [with] hiring from environmentally and economically disadvantaged communities." The Department initiated its Strategic Long-Term Resource Plan in September 2021 with a stakeholder process and incorporating the Clean Grid LA Plan and key findings from the LA100 Study for Board consideration.

As previously noted, the Department released a final version of the 2022 Strategic Long-Term Resource Plan in July 2023. The 2022 Strategic Long-Term Resource Plan models three cases for achieving 100% carbon-free energy by 2035, as well as a reference case used for comparison purposes, that represents the minimum investments needed to comply with the requirements of SB 100, which establishes the State policy goal of achieving the supply of all retail sales of electricity in California from renewable and carbon-free resources by 2045 (see "FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY – California Climate Change Policy Developments"). The 2022 Strategic Long-Term Resource Plan utilizes the same modeling methodology and approach as the LA100 Study, and includes a general assessment of the revenue requirements and rate impacts (preliminary, averages) to support a recommended resource plan through 2035 and 2045. For each of the three cases modeled, the net present value of the estimated total cumulative bulk power portfolio cost across the study horizon of 2022 through 2045 is in excess of $80 billion. In June 2024, the OPA issued a review of the 2022 Strategic Long-Term Resource Plan, focused on the potential rate impacts of the plan. In its review, the OPA noted that the estimated average annual impact on rates for 2022 through 2035 of the three cases modeled in the 2022 Strategic Long-Term Resource Plan to achieve carbon-free energy by 2035 ranged from approximately 7.7% to 8.3%, as compared to approximately 4.8% for the SB 100 comparison case (roughly 90% clean energy by 2045). The 2022 Strategic Long-Term Resource Plan represents only a conceptual plan and encompasses numerous challenges related to availability of technology, implementation feasibility, system reliability and affordability. The 2022 Strategic Long-Term Resource Plan does not include potential cost savings from new sources of funding such as the federal Inflation Reduction Act, the federal Bipartisan Infrastructure Law, and state and federal grants. The next iteration of the Department's Strategic Long-Term Resource Plan, the 2024 Strategic Long-Term Resource Plan will be an update to the 2022 Strategic Long-Term Resource Plan, and will focus on understanding rate drivers and additional clean energy opportunities to refine and optimize costs over the long-term.

Energy Efficiency

General. The Charter authorizes the Department to engage in and finance activities related to the efficient use of energy and a number of State laws expressly require utilities such as the Department to collect and spend funds for these activities. The Department has a commitment to energy efficiency and continues to pursue cost-effective means of reducing or avoiding the need to generate electricity (particularly during peak periods). These activities defer the need to acquire costly new generating facilities, improve the value of electric service to customers and increase the Department's overall load factor, thereby reducing or avoiding negative environmental impacts from power generation. Moreover, State laws enacted in 2005 and 2006 require POUs, such as the Department, in procuring energy, to first implement all available energy efficiency and demand reduction resources that are cost effective, reliable and feasible, and to provide annual reports to customers and to the CEC describing their investment in energy efficiency and demand reduction programs. AB 2021, which became a law in 2007, required IOUs and POUs to identify energy efficiency potential and establish annual efficiency targets to enable the State to meet the goal of reducing total forecasted electricity consumption by 10% by 2020. The Department adopted a goal in August 2014 of achieving up to 15% energy savings by the end of 2020, which was achieved. The Department is now focused on a goal of achieving additional energy savings of 3,434 GWhs from 2023 to 2035, surpassing the 1,802 GWhs of projected savings reflected in the LA100 Study.

Program and Portfolio Highlights. The Department's balanced portfolio of programs provides opportunities for all customers to benefit from cost effective energy efficiency. This approach targets large energy users and hard-to-reach customers who would not otherwise be able to invest in energy efficiency services, broadly addresses energy end uses in the built environment, focuses on reducing consumption during times of peak demand, and provides quality job opportunities for the local workforce. These programs include financial incentives for the installation of a variety of efficiency measures, free energy saving products, technical assistance incentives for business and industry, codes and standards, and education and awareness. The following list provides examples of programs that demonstrate the portfolio's ability to reach all customer types.

Comprehensive Affordable Multifamily Retrofits. The Comprehensive Affordable Multifamily Retrofits (the "CAMR") program provides low-income tenants and affordable housing property owners access to energy efficiency retrofits, building electrification measures, and on-site solar installation. The participating housing providers receive free energy assessments and assistance in scoping retrofit projects based on opportunities for energy savings, cost reductions, and GHG emissions reduction. Participating properties must meet affordability requirements of at least 66% of households at or below 80% of the area median income, consist of five or more units, and install energy improvements that equate to at least 10% in energy savings.

Efficient Product Marketplace. The Efficient Product Marketplace (the "EPM") program provides customers an opportunity to research, locate, and purchase energy efficient products from a single website. It offers a point of sale credit option to customers during their online purchases, eliminating the need for completing a rebate application. The EPM also provides customers with the ability to customize a solar system for their home and compare and choose offers from a list of local third-party vendors.

Food Service Program. For in-store purchases, the Food Service Program offers an instant rebate as a line item discount directly on their sales invoice for eligible equipment. The Food Service Program is intended to influence commercial food service vendors to stock and sell energy-efficient equipment. Beginning in 2024, the Food Service Program will start offering electrification incentives for all electric commercial cooking equipment & appliances.

Customer Performance Program. The Custom Performance Program (the "CPP") provides cash incentives for energy savings achieved through the implementation and installation of various energy efficiency measures and equipment that meet or exceed Title 24 or industry standards. Measures may include but are not limited to equipment controls, industrial process, retrocomissioning, chiller efficiency, and/or other innovative energy savings strategies.

The CPP's Custom Express fast tracks smaller, less energy-intensive projects with deemed energy savings projections to help expedite application processing and get customers paid faster, while the CPP's Custom Calculated conducts an in-depth energy savings analysis to custom calculate customers' individual efficiency projects' energy savings. The CPP has achieved over 610 GWhs of energy savings since 2007. In mid-2024 CPP will be rebranded as Business Offerings for Sustainable Solutions (BOSS). The new program will also offer electrification incentives for space/water heating end uses.

Commercial Lighting Incentive Program. The Commercial Lighting Incentive Program ("CLIP") offers customers incentives to install newly purchased and installed energy-efficient lighting and controls. CLIP currently provides incentives to customers whose monthly electrical use is greater than 200 kilo-watts (kW). CLIP's calculated savings approach allows customers to tailor their lighting efficiency upgrades to meet their lighting needs better, attain greater energy savings, and receive higher incentives. Commercial lighting programs have achieved over 821 GWhs of energy savings since 2000.

Commercial Direct Install Program. The Commercial Direct Install ("CDI") Program is a free direct-install program that targets small, medium, and large business customers in the Department service territory. The CDI program is available to qualifying businesses whose average monthly electrical demand is 250 kW or less; CDI has achieved 521 GWhs of energy savings since its inception in 2008.

Home Energy Improvement Program. The Home Energy Improvement Program ("HEIP") is a comprehensive direct install whole-house retrofit program that offers residential customers a full suite of free products and services to improve the home's energy and water efficiency by upgrading/retrofitting the home's envelope and core systems. While not limited to low-income customers, HEIP's priority is to serve the neediest customers.

Refrigerator Exchange Program. The Refrigerator Exchange Program ("REP") is a free refrigerator replacement program designed to target customers that qualify on either the Department's Low-Income or its Senior Citizen/Disability Lifeline Rates as well as Multi-Residential or Non-Profit customers. The program was expanded to include the following entities, multi-family or mobile home communities, civic, community, faith-based organizations, and educational institutions. The REP leverages a third party contractor, ARCA (Appliance Recycling Centers of America), to administer the program's delivery and provide energy-efficient refrigerators for this customer segment to replace older, inefficient, but operational models. Additionally, customers can pair the REP with the Window Air Conditioner Recycling Program, which offers a $25 rebate to residential customers to turn-in their old window air conditioners, achieving an energy savings of 106 GWhs since 2007.

LED Streetlight Program. The LED streetlight program provided a $48 million loan to the City of Los Angeles to enable it to ultimately install over 180,000 highly energy efficient LED streetlights and reduce its consumption of electricity as a result. This program is now completed, and the loan has been repaid by the City. As a result, this model is being expanded with a new $24 million loan to retrofit decorative street lighting with LED streetlights throughout the City.

Program Analysis and Development Program. The Program Analysis and Development Program is a non-resource program that covers support activities related to the energy efficiency portfolio, which are not included in individual programs. These activities include but are not limited to, developing new programs, conducting special studies and pilot programs, participation in technical professional groups, and the investment in external studies. The Department has contributed to several research studies as it relates to building electrification, including NBI's Building Electrification Technology Roadmap and E3's Residential Building Electrification in California. Since the results of the studies, the Department has been crafting incentives for customers to electrify building end uses leveraging existing program delivery mechanisms to promote electric space and water heating, cooking and drying that have traditionally used natural gas as a fuel. While building electrification presents an opportunity to produce additional revenue, the Department's activities have been focused on promoting measures that effectively result in net utility bill reduction (inclusive of gas and electricity). This is directed towards maintaining a high level of customer benefit and satisfaction.

The Department has also partnered with the NREL to develop a technology prioritization tool as the Department ramps up its technology assessment efforts in the Emerging Technologies program. The tool helps prioritize the most impactful technologies that would improve energy efficiency for customers. These technology assessment efforts in the Emerging Technologies program incorporate many of the tools and methods used in the LA100 Study. See "THE POWER SYSTEM – LA100 Study" above.

The set of tools and methods used in the LA100 Study allows the Department to assess potential impacts as it relates to an emerging technology using the development of the building demand modeling that includes baseline consumption and characteristics data for residential and commercial building stock. This effort will analyze multiple use cases to empower the Department to provide more accurate potential studies and develop a pipeline of new technology assessments to determine the appropriate intervention required to get maximum benefits. The goal is to quantify achievable contributions towards goals set by State and local energy policies for the lowest cost.

From 2000 through June 2024, the Department has spent approximately $1.8 billion on its energy efficiency programs, and these programs are estimated to have reduced long-term peak period demand and consumption by approximately 978 MW and resulted in approximately 5,806 GWhs of energy savings. Through the energy-efficiency rebate and incentive programs, residential and commercial customers saved approximately 277 GWh incrementally for Fiscal Year 2023-24, falling short of energy savings targets by 109 GWh. The Department spent approximately $125 million on energy efficiency programs for Fiscal Year 2023-24 of its approximately projected $183 million budgeted amount for such Fiscal Year. The Department will continue to evaluate the delivery and implementation of energy efficiency measures that support system reliability and resiliency while enabling customers to manage their power better. The Department anticipates increasing its expenditures for energy efficiency and building electrification programs in future years, based on portfolio planning utilizing the results of the Department's energy efficiency and building electrification potential studies.

Fuel Supply for Department-Owned Generating Units and Apex Power Project

Natural gas is used to fuel 100% of the Los Angeles Basin Stations. The Department's fossil fuel requirements for the Los Angeles Basin Stations to meet the electric load requirements of its customers in the City (referred to as "native load") were 41 billion equivalent cubic feet of natural gas during Fiscal Year 2023-24. In addition, the Department's fossil fuel requirements for the Apex Power Project were 17 billion equivalent cubic feet of natural gas during Fiscal Year 2023-24. In the early 2000s, the Department determined that acquiring natural gas reserves was advantageous, reasonable and prudent to ensure stable, long-term natural gas supplies to help meet future power generation demands. In June 2005, the Department, the Turlock Irrigation District and SCPPA (acting on behalf of its member California cities of Anaheim, Burbank, Colton, Glendale and Pasadena) acquired rights in natural gas-producing properties from the Anschutz Pinedale Corporation. Under the acquisition agreement, the Department obtained an approximately 74.5% ownership interest in a $300 million acquisition of leases of gas-producing property in Sublette County, Wyoming. This acquisition provided approximately 2.01% of the Department's average daily natural gas requirements for Fiscal Year 2022-23. No increase to this natural gas-producing program is expected at this time, however further capital investment in such program will be re-evaluated if market conditions change and the price of natural gas rises.

The Department obtains its remaining natural gas requirements through a competitively bid spot purchase program or through forward physical gas purchases for a specified period of time. The price of natural gas delivered into Southern California has fluctuated over the past few years and the Department expects prices to continue to fluctuate. To mitigate the effects of natural gas price volatility, the Department includes as part of the Electric Rates certain pass-through cost adjustments that provide recovery of natural gas and other fuel costs. See "ELECTRIC RATES – Rate Setting." In addition, the City Council enacted an ordinance to authorize the Department to enter into financial hedge contracts with respect to natural gas purchases to stabilize fuel costs for native load. See "Note (8) Derivative Instruments" of the Department's Power System Financial Statements. Under this ordinance, the Department's General Manager also may enter into biogas supply agreements for a period not to exceed ten years, so long as certain conditions are met. The use of natural gas swaps, derivatives and other price hedging arrangements are subject to risk management policies and review procedures established by the Board. The Department has developed a natural gas procurement strategy that includes a program of entering into financial hedges with various counterparties that have permitted terms of up to ten years and are intended to mitigate customer exposure to gas price volatility. The policy permits up to 75% of the Department's natural gas requirements to be hedged through various measures (including such financial hedges), although the amount hedged in a given year may vary.

As of May 31, 2024, the Department had entered into financial natural gas hedges in various notional amounts per Fiscal Year for each Fiscal Year through Fiscal Year 2028-29 with an aggregate notional amount of approximately 80.0 million MMBtu. These financial hedges cover up to approximately 50% of the Department's natural gas requirements based on the latest budget for the Fiscal Years through 2028-29. Tables describing the notional amount for each Fiscal Year and the durations of the hedges, as well as a discussion of the credit, basis and termination risks associated with such hedges as of June 30, 2023 and 2022, can be found in Note (8).

The Department has previously used a physical delivery natural gas hedge program that was designed to hedge up to 50% of its forecasted usage. However, due to the limitation of gas injections at the SoCalGas Aliso Canyon storage facility, there is some uncertainty about intrastate gas transmission capacity available for electric generators. Consequently, the Department reduced the amount of forward physical gas purchased and limited the term of forward purchases based on the Department's quarterly term plan forecasting periods.

The Department has firm interstate natural gas transportation capacity on the Kern River Pipeline System. The total amount of capacity is sufficient to transport 92% of the average amount of natural gas needed for the Los Angeles Basin Stations under current Department forecasts. Additional interstate pipeline capacity, if needed, is acquired through federally-approved capacity brokering programs or through gas purchases bundled with interstate transportation delivered into the SoCalGas intrastate system.

Intrastate transportation and balancing services are provided to the Department by SoCalGas sufficient to meet 100% of the Los Angeles Basin Stations' requirements under SoCalGas's Basic Transportation Service program ("BTS"). This enables the Department to deliver Kern River Pipeline System gas to the BTS receipt points in the State.

As of May 31, 2024, approximately 50% and 40% of the Department's projected natural gas needs have been hedged for Fiscal Year 2024-25 and Fiscal Year 2025-26, respectively, through financial natural gas hedges and gas reserves. This ratio declines such that by Fiscal Year 2028-29, approximately 9% of projected natural gas needs are hedged. The Department typically hedges a higher percentage of its natural gas needs as the operating year approaches. The goal of the current natural gas hedging program is to hedge up to five years forward from the current Fiscal Year, with the next Fiscal Year hedged up to 50% and the fifth Fiscal Year hedged up to 10%. The Department periodically reviews the goals of its natural gas hedging program.

The SoCalGas Aliso Canyon underground natural gas storage facility in the Porter Ranch area of Los Angeles leaked between October 23, 2015 and February 18, 2016 and was ordered to cease its injections by State agencies until testing of all operating wells was completed. The volume in this storage field, SoCalGas's largest, was reduced for safety reasons to a maximum of only 41 billion cubic feet ("BCF"), from its design maximum of 86 BCF. In August 2023, the CPUC approved an increase in the allowable storage at the facility to 68.6 BCF. There have been no localized natural gas curtailments impacting the Department and there have been no impacts to the Department from SoCalGas operations thus far. With the CPUC's August 31, 2023 vote to increase the Aliso Canyon interim storage limit, the agency also ended SoCalGas's need to comply with the Aliso Canyon Withdrawal Protocol as part of the implementation of that decision. In reaching its August 2023 decision, the CPUC determined that "restrictions on Aliso Canyon contributed to last year's natural gas price spikes and that removal of the Commission's storage level limitation provides a significant tool to mitigate future gas price spikes. To effectively implement this decision, the [CPUC] Energy Division is removing the Withdrawal Protocol to allow customers increased flexibility to use Aliso Canyon to moderate gas and electricity prices."

Water Supply for Department-Owned Generating Units

Water required for the operation of generating stations owned by the Department is secured from a number of sources. The Harbor Generating Station, Haynes Generating Station and Scattergood Generating Station use Pacific Ocean water for power plant cooling purposes. However, the Department is undertaking a long-term program of replacing the coastal generating units to eliminate the use of ocean water at these three locations in part to meet requirements of the SWRCB and the City's plans to eliminate the future use of once-through-cooling for these plants and replace them with clean energy alternatives. See "FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY – Environmental Regulation and Permitting Factors – *Water Quality – Cooling Water Process – State Water Resources Control Board" and "– Regional Requirements – Thermal Discharges at Harbor Generating Station and Haynes Generating Station."* The Valley Generating Station, which is located inland, utilizes recycled water for cooling.

Spot Purchases

The Department purchases energy from the Bonneville Power Administration ("BPA") and other Pacific Northwest utilities under short-term "spot" arrangements to be delivered over the Pacific DC Intertie. For further information on the Pacific DC Intertie, see "– Transmission and Distribution Facilities – *Pacific DC Intertie and Sylmar Converter Station*." These purchases are used by the Department in conjunction with other resources for Power System operation. In addition, purchases of energy are made from other entities located in the Southwest. Spot purchases have generally been made at prices that permit economical operation of the Power System and that are comparable to the Department's costs for producing power from its own resources.

The availability of economical energy on the spot market has fluctuated greatly in recent years. Historically, the Department has not been dependent on such purchases to meet its customers' requirements. Although the Department currently continues to find economical spot purchase opportunities (including some for renewable energy), it cannot predict the future availability of power from either the Pacific Northwest or the Southwest for purchases at prices below the Department's costs for producing power from its own resources. The Department has increased its volume activity with the Cal ISO, including the purchase and sale of energy, as well as providing ancillary services, when excess capacity exists on its system.

Cogeneration and Distributed Generation

Currently thermal cogeneration installed in the Department's service area consists primarily of cogeneration projects of industrial and commercial customers. This totals approximately 322 MW nameplate capacity. Some cogeneration projects sell excess energy to the Department under interconnection agreements.

Distributed generation (the generation of electricity at or near the point of use) within the Department's service area currently consists primarily of cogeneration projects at customer facilities. Distributed generation also includes smaller generating units such as solar photovoltaic cells, fuel cells, micro-turbines and other smaller combustion engines. The Department manages a new technology demonstration program to assess the viability of some of these technologies. The Department also supports the development of new technologies through customer incentive programs. See "– Renewable Power Initiatives" and "– Energy Efficiency." These technology advancements may change the nature of energy generation and delivery and may materially affect the operating and financial position of the Department. For example, behind-the-meter resources such as cogeneration, demand response, and energy efficiency may have the effect of reducing customer demand, potentially diminishing revenue for the Department. On the other hand, if such resources are able to be successfully deployed during peak demand hours, this could reduce the Department's need to procure additional utility-scale resources to meet that peak demand.

Excess Capacity

The Department uses its extensive transmission network to sell excess generating capacity into the California, Northwest and Southwest energy markets. Net income from those sales is used to reduce costs to the Department's retail customers (primarily by applying revenues to the costs of capital improvements or toward an electric rate stabilization account in the Incremental Electric Rate Ordinance). With equipment outages, retirement of equipment, anticipated load growth and changes in GHG regulations which impact emission allowances, the Department anticipates that revenue from excess energy sales will be less certain than in the past. Wholesale revenues, as shown in "SELECTED FINANCIAL INFORMATION" under "OPERATING

AND FINANCIAL INFORMATION – Financial Information," have accounted for less than 2% of overall Power System revenues in recent years.

Transmission and Distribution Facilities

Electricity from the Department's power generation sources is delivered to customers over a complex transmission and distribution system. To deliver energy from generating plants to customers, the Department owns and/or operates over approximately 15,000 miles of alternating current ("AC") and direct current ("DC") transmission and distribution circuits operating at voltage classes ranging from 120 volts to 500 kV, of which over approximately 11,000 miles are above ground. In addition to using its transmission system to deliver electricity from its power generation resources, under the OATT the Department transmits energy for others through such system when surplus transmission capacity is available and such transmission is permitted by the Master Resolution. As the operating agent of the Pacific DC Intertie, the Southern Transmission System, the Mead-Adelanto Transmission Project and certain Navajo-McCullough transmission facilities (all such facilities being described below), the Department, at the direction of and for the benefit of the respective co-owners/participants, transmits energy for the co-owners of, or participants in, these facilities.

Pursuant to AB 1890, signed into law on January 1, 1997, as part of the deregulation of the State electric industry, municipal utilities such as the Department were encouraged, but not required, to transfer operational control of their electric transmission facilities to the Cal ISO. The Department owns and operates in excess of 25% of the transmission facilities in the State. While the Department has not transferred operational control of its transmission facilities to the Cal ISO, the Department interacts with the Cal ISO on a regular basis. The Department serves as the scheduling coordinator for the delivery of that portion of the Department's energy that requires use of any part of the Cal ISO grid. The Department also coordinates with the Cal ISO with respect to some lines that are jointly owned by the Department and others. The Department is responsible for the costs associated with its use of the Cal ISO grid. The Department is registered as a participant in wholesale transactions in the Cal ISO market.

On April 1, 2021, the Department began participating in Cal ISO's Western EIM. The Western EIM is a real-time energy market that provides sub-hourly dispatch of participating resources for balancing supply and demand every five minutes, using the least-cost energy. As a Western EIM participant, the Department voluntarily provides excess energy capacity for dispatching to other participating utilities, while maintaining control of its generation assets and ratemaking authority. The Western EIM also provides an opportunity for the Department to purchase low-cost excess energy. The Department is participating voluntarily in order to tap into resources across a larger geographic area that includes eleven western states and the Canadian Province of British Columbia. Through its participation, the Department has experienced benefits from purchasing low cost energy during periods of high generation from renewables, a reduction in GHG emissions, as well as financial benefits from selling energy to the market during periods of low supply and higher prices. This helps lower the cost of delivery of power to its customers, and foster integration of renewable energy.

Legislation considered from time to time by the U.S. Congress and the State could potentially increase the level of jurisdictional control over the generation, transmission and distribution assets that comprise the Department's Power System and could encourage voluntary participation by the Department in a regional transmission organization. The City opposes any participation in a regional transmission organization that would be mandatory. The Department monitors any potential restrictions regarding control of transmission rates, authority to finance the Power System using bonds and use of the Power System to deliver electric power to the City.

Certain transmission facilities available to the Department are discussed below.

Southern Transmission System. The Southern Transmission System (the "STS") is an approximately 490-mile, ±500 kV DC transmission line from the Intermountain Generating Station, near Delta, Utah, to Adelanto, California, together with an AC/DC converter station at each end of the line. The STS is owned by IPA and is one of three major components of the IPP. See "– Jointly-Owned Generating Units and Contracted

Capacity Rights in Generating Units – *Intermountain Power Project*." After the completion of an upgrade to its capacity in December 2010, a maximum of 2,400 MW can be transmitted over the STS. The Department's entitlement in the capacity of the STS is currently approximately 1,428 MW and is expected to increase to 2,172 MW in 2027 as a result of the Department increasing its share of the STS to 90.5% in accordance with the IPP Renewal Power Sales Contract. IPA is undertaking an approximately $2.7 billion renewal project to refurbish or replace the existing Adelanto Converter Station and Intermountain Converter Station with new HVDC stations on available land adjacent to the existing converter stations at Adelanto and IPP, which replacement components are currently scheduled for commercial operation on various dates through April 2028. The new converter stations will tie into the existing AC switchyards and connect to the existing DC transmission line. The schedule and cost estimate for the STS renewal project reflect design changes authorized by the IPA board of directors in November 2023 to facilitate an increase in the capacity of the STS from 2,400 to 3,000 MW to be undertaken in the future. The Department entered into a transmission service contract with SCPPA in 1983 to define the terms for transmission service on a "take-or-pay" basis for the Department's 59.5% entitlement right to capacity in the STS that it assigned to SCPPA in order for SCPPA to incur indebtedness sufficient to generate funds to finance the original construction of the STS. This service provides for the transmission of energy from the Intermountain Converter Station to the Adelanto Converter Station until 2027. The Department has negotiated a renewal transmission service contract with SCPPA for the same purpose as the original transmission service contract on a "take-or-pay" basis to allow SCPPA to be able to continue handling financings of the STS (including financing for costs of the ongoing upgrades to the Switchyard and converter station replacements) for the remainder of the term of the Department's participation in the IPP until 2077. SCPPA has issued bonds to finance a portion of the costs of the STS renewal project. See "OPERATING AND FINANCIAL INFORMATION – Take-or-Pay Obligations."

Northern Transmission System. The Northern Transmission System (the "NTS") includes two approximately 50-mile, 345 kV AC transmission lines from IPP to the Mona Substation in Northern Utah, and one approximately 144-mile, 230 kV AC transmission line from IPP to the Gonder Substation in Nevada. The NTS was constructed for the delivery of power from IPP to certain municipalities in Utah and certain cooperative purchasers. Capacity on the NTS is available to the Department through the IPP Excess Power Sales Agreement. The Department can have up to a maximum NTS share allocation of 43.141% of the total capacity depending on the generation deemed excess by the 29 Utah municipalities and cooperatives that have access to such power. The capacity from IPP to Mona is 1,400 MW; the capacity from Mona to IPP is 1,200 MW; the capacity from IPP to Gonder is 200 MW; and the capacity from Gonder to IPP is 117 MW.

Pacific DC Intertie and Sylmar Converter Station. The Pacific DC Intertie is an approximately 846-mile, ±500 kV DC transmission system that connects Southern California to the hydroelectric and wind generation resources of the Pacific Northwest. A maximum of 3,210 MW can be transmitted over the entire Pacific DC Intertie System. The Department owns a 40% interest in the southern portion of the Pacific DC Intertie from the Nevada-Oregon border to its southern terminus at the Sylmar Converter Station in Sylmar, California and is the operating agent of the southern portion of the Pacific DC Intertie. The northern portion of the Pacific DC Intertie is owned and operated by BPA and extends from the Nevada-Oregon border to BPA's Celilo Station in The Dalles, Oregon.

Devers-Palo Verde Transmission Line. The Devers-Palo Verde Transmission Line is an approximately 250-mile, 500 kV AC line owned by Edison that connects the PVNGS with the Devers Substation outside Desert Hot Springs, California. As part of an exchange agreement, the Department purchases up to 368 MW of bi-directional firm transmission service on the Devers-Palo Verde Transmission Line from Edison (the "Devers-Palo Verde Agreement") at the rate being charged by the Cal ISO for that same service. The Devers-Palo Verde transmission path now consists of the Devers-Colorado River and Colorado River-Palo Verde transmission lines. The Department has the right to terminate the service upon 12 months written notice.

Mead-Phoenix Transmission Project. The Mead-Phoenix Transmission project is an approximately 259-mile, 500 kV AC transmission line which originates at the Westwing substation in Phoenix, Arizona, connects with the Mead substation near Boulder City, Nevada and terminates at the Marketplace substation nearby. The Mead-Phoenix Transmission Project is currently owned by SCPPA, APS, Salt River Project, Western and Startrans IO, L.L.C. In 2016, SCPPA, on behalf of the Department, acquired an additional interest in the Mead-Phoenix Transmission Project for the benefit of the Department through the purchase of the M-S-R Public Power Agency ("M-S-R") ownership share (11.5385% of the Westwing-Mead component and 8.09930% of the Mead-Marketplace component) of the Mead-Phoenix Transmission Project. After such acquisition, the Department's share is 57.732% of SCPPA's member-related interests in the Westwing-Mead component of the Mead-Phoenix Transmission Project (SCPPA's member-related interests comprise 29.8462% of the entire Westwing-Mead component of the Mead-Phoenix Transmission Project) and 39.6459% of SCPPA's member-related interests in the Mead-Marketplace component of the Mead-Phoenix Transmission Project (SCPPA's member-related interests comprise 30.5075% of the entire Mead-Marketplace component of the Mead-Phoenix Transmission Project). A maximum of 1,923 MW can be transmitted over the Westwing-Mead component of the Mead-Phoenix Transmission Project, of which the Department has an entitlement share of 332 MW. A maximum of 2,600 MW can be transmitted over the Mead-Marketplace component of the Mead-Phoenix Transmission Project, of which the Department has an entitlement share of 315 MW. The Department's average share of the Mead-Phoenix Transmission Project components is 50.39% of SCPPA's member-related interests in the Mead-Phoenix Transmission Project. The Department has entered into transmission service contracts with SCPPA that obligate the Department until 2030 to pay for its share of SCPPA's member-related interests in the Mead-Phoenix Transmission Project on a "take-or-pay" basis as an operating expense of the Power System. Payments made by the Department associated with SCPPA's member-related interests in the Mead-Phoenix Transmission Project include a share of the fixed operating costs and debt service on bonds issued by SCPPA for SCPPA's member-related interests in the Mead-Phoenix Transmission Project. See "OPERATING AND FINANCIAL INFORMATION – Take-or-Pay Obligations."

Mead-Adelanto Transmission Project. The Mead-Adelanto Transmission Project is an approximately 202-mile, 500 kV AC transmission line between the Adelanto substation, near Victorville, California and the Marketplace substation, near Boulder City, Nevada. The Mead-Adelanto Transmission Project was constructed by its owners, currently, SCPPA, Western and Startrans IO, L.L.C., in connection with the Mead-Phoenix Transmission Project. In 2016, SCPPA, on behalf of the Department, acquired an additional interest in the Mead-Adelanto Transmission Project for the benefit of the Department through the purchase of M-S-R's 17.5% ownership share of the Mead-Adelanto Transmission Project. After such acquisition, the Department's share is 48.878% of SCPPA's member-related interests of the Mead-Adelanto Transmission Project (SCPPA's member-related interests comprise 85.4167% of the entire Mead-Adelanto Transmission Project). A maximum of 1,291 MW can be transmitted over the Mead-Adelanto Transmission Project, of which the Department has an entitlement share of 539 MW. The Department has entered into transmission service contracts with SCPPA that obligate the Department until 2030 to pay for its share of SCPPA's member-related interests in the Mead-Adelanto Transmission Project on a "take-or-pay" basis as an operating expense of the Power System. Payments made by the Department associated with SCPPA's member-related interests in the Mead-Adelanto Transmission Project include a share of the fixed operating costs and debt service on bonds issued by SCPPA for SCPPA's member-related interests in the Mead-Adelanto Transmission Project. See "OPERATING AND FINANCIAL INFORMATION – Take-or-Pay Obligations."

Navajo-McCullough Transmission Line. The Navajo-McCullough Transmission Line is a 274-mile, 500 kV AC transmission line that originates at the Navajo Project near Page, Arizona, connects through the Crystal Substation near Las Vegas, Nevada and terminates at the McCullough substation, near Boulder City, Nevada. The Department owns 48.9% of the Navajo-McCullough Transmission Line, which was constructed as a part of the now-retired Navajo Generating Station. The Crystal Substation was constructed by NV Energy. NV Energy owns 100% of the Crystal Substation on behalf and for the benefit of the Navajo Project, including the Department.

Eldorado Transmission System. The Eldorado Transmission System's major components are the 59-mile, 500 kV AC Mohave-Eldorado transmission line, the 500 kV Mohave Switchyard, the Eldorado substation, which is comprised of a 220 kV switchyard and a 500 kV switchyard, and two parallel 15-mile 220 kV AC Eldorado-Mead transmission lines. Pursuant to a Co-Tenancy and Operating Agreement, the Department is a 30% co-owner of the Mohave Switchyard, a 29.3% co-owner of the 500 kV switchyard, an 11.3% owner of the 220 kV switchyard, and a 15.1% co-owner of the transformers between the 500 kV and 220 kV switchyards, each of which is a part of the Eldorado Substation. The Department's ownership represents 716 MW of capacity on the Mohave-Eldorado transmission line and 215 MW of capacity on the two parallel 15-mile 220 kV AC Eldorado-Mead transmission lines.

Barren Ridge Renewable Transmission Project. The Barren Ridge Renewable Transmission Project involved the expansion of the Barren Ridge Switching Station in order to increase the 3,119 MVA transmission capacity of renewable energy flowing into the Los Angeles Basin from generating facilities in Owens Valley, Kern County and the Tehachapi Mountains by 2,000 MVA.

Projected Capital Improvements

The Department has developed a series of Power System resource plans with each plan updating and refining the previous plan. The plans are developed in conjunction with the Department's strategic planning to meet its goals of continuing to provide reliable service to customers, maintaining a competitive price for the Power System's services and providing environmental leadership. Such resource plans act as guidance for the Department in implementing more specific short-term and long-term financial plans.

Based on the Department's December 2023 Retail Electric Sales and Demand Forecast, the Department anticipated that gross customer electricity consumption would increase from Fiscal Year 2021-22 to Fiscal Year 2031-32 at a forecasted rate of approximately 1.58% per year without consideration of the Department's measures to promote energy efficiency and distributed generation. That load growth rate reflects, in the later part of the ten-year planning period, increases due in part to fuel switching in the transportation sector including the increase of plug-in hybrid and battery electric vehicles. In accordance with the Power System's recent resources plans, significant energy efficiency measures have been planned and are being implemented as a cost effective resource, along with support for customer solar projects. The Department achieved its energy efficiency goal of 15% energy efficiency savings by 2020 and is now focused on an additional 3,431 GWhs of energy savings by 2035. Enhancement and expansion of electric transmission resources will enable access to renewable energy resources. Certain in-basin energy projects will assist in integrating intermittent renewable resources into the Power System. Capital investments in the transmission and distribution system, including new business service and electric feeder lines, are required to support future growth. New control and monitoring systems are needed to continue to provide reliable and secure system operations. See " – Power System Reliability Program" below.

Power System Reliability Program. A significant power outage in 2006 caused the Department to conduct an evaluation of its electrical infrastructure and led to the development of a comprehensive distribution-focused power reliability program initially referred to as the "Power Reliability Program" with the following major components: (a) mitigation of problem circuits and stations based on the types of outages specific to the facility, including among other things, timely, permanent repairs of distribution circuits after a failure and fixing poorly performing circuits, (b) proactive maintenance and capital improvements that take into account system load growth and the inspections and routine maintenance that must take place to identify problems before they occur, (c) replacement cycles at the facilities that are in alignment with the equipment's life cycle such as replacing aging underground cables, overhead poles and circuits and substation equipment and (d) replacement of overloaded transformers. In 2013, another evaluation was completed and the program was expanded and renamed the "Power System Reliability Program." The Power System Reliability Program assesses all Power System assets affecting reliability in an integrated and comprehensive manner and proposes corrective actions as well as capital expenditures designed to minimize future outages and maintain reliability in the short and long term. The Power System Reliability Program includes the establishment of metrics and indices to help prioritize infrastructure replacement and expenditures for all major functions of the Power System, including distribution, transmission, generation, and substations. The Power System Reliability Program has been and is anticipated to be updated on an annual basis to adjust to varying Power System conditions and resource allocations.

Projected Capital Expenditures. As indicated in the table below, for Fiscal Year 2024-25 through Fiscal Year 2028-29, the Department expects to invest approximately $14.3 billion in capital improvements to the Power System.

EXPECTED CAPITAL IMPROVEMENTS TO THE POWER SYSTEM
FIVE-YEAR PERIOD BEGINNING JULY 1, 2024
(in Millions)

	5-Year Totals
Infrastructure: Various Generation Station Improvements	$ 2,070
IT Infrastructure*	512
Energy Efficiency	1,066
Power System Reliability Program	5,918
Renewable Portfolio Standard (RPS): Wind Projects, Renewable Energy Project Development, Renewable Transmission Projects, RPS Storage	2,641
Power System Resource Plan	5
Shared Services: Facilities, Customer Services, Fleet	2,059
Total Power System Capital Improvements	$14,269

Source: Department of Water and Power of the City of Los Angeles.

* For planning purposes, the power financial plan includes a proposed IT Cost Adjustment Factor (ITCAF) with an effective date of July 1, 2025. This proposed ITCAF is designed to recover the information technology (IT) expenses related to enterprise resource planning, smart grid, cybersecurity, and cloud infrastructure programs. These IT expenses include both capital and operation and maintenance expenses that are being allocated among base revenue supported categories such as operating support, infrastructure and other pass-through supported categories.

Note: Total may not equal sum of parts due to rounding.

The table below indicates, for Fiscal Year 2024 through Fiscal Year 2028-29, the expected funding sources for the capital improvements to the Power System expected for such Fiscal Years.

EXPECTED FUNDING SOURCES FOR CAPITAL IMPROVEMENTS
TO THE POWER SYSTEM
(in Millions)

Fiscal Year Ending (June 30)	Internally Generated Funds	External/Debt Financing	Total Capital Expenditures(1)
2025	$1,270	$1,126	$2,396
2026	969	1,661	2,630
2027	1,382	2,005	3,387
2028	992	2,018	3,011
2029	1,071	1,774	2,845
	$5,685	$8,584	$14,269

Source: Department of Water and Power of the City of Los Angeles.

(1) Net of reimbursements to the Department.

Note: Totals may not equal sum of parts due to rounding.

The particular programs and commitments for capital improvements to the Power System are subject to review by Department stakeholders and others. The estimated costs of, and the projected schedule for, the expected capital improvements to the Power System and the Department's other capital projects are subject to a number of uncertainties. The ability of the Department to complete such capital improvements may be adversely affected by various factors including: (i) estimating errors, (ii) design and engineering errors, (iii) changes to the scope of the projects, (iv) delays in contract awards, (v) material and/or labor shortages, (vi) unforeseen site conditions, (vii) adverse weather conditions, (viii) contractor defaults, (ix) labor disputes, (x) unanticipated levels of inflation, (xi) environmental issues, (xii) the ability to access the capital markets at particular times and (xiii) delays in approvals of rate increases. No assurance can be given that the proposed projects will not cost more than the current budget for these projects. Any schedule delays or cost increases could result in the need to issue additional obligations and may result in increased costs to the Department. All payments of project costs associated with projected capital improvements are subject to Board approval.

OPERATING AND FINANCIAL INFORMATION

The Department's service area consists of the City, where over 1.5 million customers are served, and certain areas of Inyo and Mono Counties in the State, where approximately 5,220 customers are served. As of March 31, 2024, 33% of the Power System's total energy sales (measured in MWhs) were to residential customers, 62% to commercial and industrial customers and the remaining 5% to all other purchasers. Revenues from residential customers, commercial/industrial customers, and other customers were approximately 35%, 61%, and 4% of total revenue, respectively.

Summary of Operations

The table below provides certain operating information with respect to the Power System.

POWER SYSTEM
SELECTED OPERATING INFORMATION
(Unaudited)

	Nine Month Period Ended March 31		Fiscal Year Ended June 30				
Operating Statistics	**2024(1)**	**2023**	**2023**	**2022**	**2021**	**2020**	**2019**
Net Energy Load(2)	17,632	18,724	23,859	23,997	23,797	24,096	25,046
Net Hourly Peak Demand (MW)	5,453	6,216	6,216	4,911	6,106	5,637	6,201
Annual Load Factor (%)	48.81	45.64	43.81	55.79	44.49	48.66	46.11
Electric Energy Generation, Purchases and Interchanges(2)							
Generation(3)(4)	12,582	13,265	17,172	17,194	17,281	17,947	16,862
Purchases(2)	6,148	7,525	9,148	9,440	8,988	7,295	8,966
Miscellaneous Energy Receipts(2)	193	–	–	–	705	470	230
Total Energy(2)	18,923	20,790	26,320	26,634	26,974	25,712	26,058
Less:							
Miscellaneous Energy Deliveries(2)(5)	–	316	426	511	–	–	–
Losses and System Uses(2)	1,949	2,035	2,386	2,595	4,479	3,879	3,507
On-System Sales(2)	16,974	18,439	23,508	23,528	22,495	21,833	22,550
Sales of Energy(2)							
Residential	5,584	6,211	7,736	7,383	7,707	7,218	7,303
Commercial and Industrial	10,498	10,689	13,959	14,092	13,220	14,030	14,661
All Other	870	1,155	1,722	1,891	2,087	1,050	626
Total	16,952	18,055	23,417	23,366	23,014	22,298	22,590
Number of Customers – (Average, in thousands):							
Residential	1,451	1,436	1,440	1,430	1,414	1,405	1,397
Commercial and Industrial	128	129	128	128	126	126	126
All Other	7	7	7	7	7	7	7
Total	1,586	1,572	1,575	1,565	1,547	1,538	1,529

Source: Department of Water and Power of the City of Los Angeles.

(1) Data for the nine-month period ended March 31, 2024 is preliminary and subject to change. Results for the first nine months of Fiscal Year 2023-24 may not be indicative of results for full Fiscal Year 2023-24.

(2) Thousands of MWhs.

(3) Does not include energy generated at Hoover Power Plant for plant use and for the use of the Bureau of Reclamation and the cities of Boulder City, Nevada; Burbank, California; Glendale, California and Pasadena, California.

(4) Purchases from SCPPA are classified as Generation for quarterly results and Purchases for Fiscal Year end results.

(5) Deliveries include transmission loss energy paybacks and control area inadvertent interchange.

Financial Information

The tables below provide certain financial information with respect to the Power System.

POWER SYSTEM
SELECTED FINANCIAL INFORMATION
(Dollars in Thousands)
(Unaudited)

	Nine Month Period Ended March 31		Fiscal Year Ended June 30[1]				
	2024[2]	**2023**	**2023**	**2022**	**2021**	**2020**	**2019**
Operating Revenues							
Residential	$1,171,338	$1,282,913	$1,717,646	$1,637,120	$1,614,033	$1,360,648	$1,376,341
Commercial and Industrial	2,027,470	2,027,384	2,857,601	2,784,691	2,492,138	2,372,533	2,560,098
Sales for resale[3]	134,311	262,895	326,347	230,160	186,706	61,455	111,542
Other[4]	(5,907)	22,563	56,945	(58,211)	(24,399)	12,655	22,949
Total Operating Revenues	$3,327,212	$3,595,755	$4,958,539	$4,593,760	$4,268,478	$3,807,291	$4,070,930
Average Revenue per kWh Sold[5]							
Residential	0.210	0.207	0.222	0.222	0.209	0.189	0.188
Commercial and Industrial	0.193	0.190	0.205	0.198	0.189	0.169	0.175
Average Annual Residential Usage[6]	4	4	5	5	5	5	5
Operating income	$353,265	$398,651	$ 742,176	$ 800,988	$ 744,139	$ 363,981	$ 512,310
As % of revenues	10.6%	11.1%	15.0%	17.4%	17.4%	9.6%	12.6%
Adjusted Change in Net Position, excluding Power Transfer and including accounting change[7]	$366,203	$633,433	$ 833,815	$ 532,290	$ 633,942	$ 320,065	$ 459,503
Adjusted Change in Net Position, including Power Transfer and accounting change[7]	$121,508	$401,390	$ 601,772	$ 307,275	$ 415,587	$ 90,152	$ 226,946

Source: Department of Water and Power of the City of Los Angeles.

(1) Derived from the Power System Financial Statements (except for usage statistics).

(2) Data for the nine-month period ended March 31, 2024 is preliminary and subject to change. Results for the first nine months of Fiscal Year 2023-24 may not be indicative of results for full Fiscal Year 2023-24.

(3) Includes sales of power and transmission services to other utilities.

(4) Net of Uncollectible Accounts.

(5) The calculated Average Revenue per kWh Sold is based on dividing reported Operating Revenues by customer class by volumes for that customer class, including deferred revenues. The actual customer rates may differ from these calculated figures due to a variety of factors, including (1) demand and energy charges for commercial rates, (2) changes in usage between rate tiers within a customer class and between years, and (3) other factors including customer classification issues.

(6) MWh use per residential customer.

(7) "Adjusted" indicates measurements of financial and/or operating performance that are not specifically disclosed in the Power System Financial Statements. Adjustments reflect the impact of the implementation of new accounting standards, particularly GASB No. 75, which resulted in the recording of certain OPEB liabilities and a corresponding reduction in net position.

POWER SYSTEM
SUMMARY OF REVENUES, EXPENSES AND DEBT SERVICE COVERAGE
(Dollars in Thousands)
(Unaudited)

	Nine Month Period Ended March 31		Fiscal Year Ended June 30[1]				
	2024[2]	**2023**	**2023**	**2022**	**2021**	**2020**	**2019**
Operating Revenues							
Sales of Electric Energy:							
Residential	$1,171,338	$1,282,913	$1,717,646	$1,637,120	$1,614,033	$1,360,648	$1,376,341
Commercial and industrial	2,027,470	2,027,384	2,857,601	2,784,691	2,492,138	2,372,533	2,560,098
Sales for resale	134,311	262,895	326,347	230,160	186,706	61,455	111,542
Other[3]	(5,907)	22,563	56,945	(58,211)	(24,399)	12,655	22,949
Total Operating Revenues	$3,327,212	$3,595,755	$4,958,539	$4,593,760	$4,268,478	$3,807,291	$4,070,930
Operating Expenses							
Production:							
Fuel for Generation	$ 257,959	$ 380,951	$ 435,524	$ 327,813	$ 228,697	$ 207,043	$ 296,506
Purchased Power	860,265	1,090,530	1,448,692	1,309,505	1,301,394	1,242,068	1,264,133
Energy Cost	1,118,224	1,471,481	1,884,216	1,637,318	1,530,091	1,449,111	1,560,639
Maintenance and Other Operating Expenses	1,266,643	1,162,890	1,570,429	1,430,993	1,323,158	1,364,303	1,412,750
Adjusted Operating Expenses[4][6]	$2,384,867	$2,634,371	$3,454,645	$3,068,311	$2,853,249	$2,813,414	$2,973,389
Adjusted Operating Income[4][6]	$ 942,345	$ 961,384	$1,503,894	$1,525,449	$1,415,229	$ 993,877	$1,097,541
Other non-operating income and expenses, net	275,102	478,661	413,808	1,482	145,303	268,502	239,211
Contributions in aid of construction	42,956	55,904	76,942	100,865	103,459	57,692	58,373
Adjusted Change in Net Position[5][6]	$1,260,403	$1,495,949	$1,994,644	$1,627,796	$1,663,991	$1,320,071	$1,395,125
Debt Service							
Adjusted Interest[6][7]	399,174	387,062	517,818	479,482	459,413	454,074	426,577
Principal	214,040	190,315	190,315	187,683	179,405	171,925	153,664
Total debt service	$ 613,214	$ 577,377	$ 708,133	$ 667,165	$ 638,818	$ 625,999	$ 580,241
Debt Service Coverage Ratio	N/A	N/A	2.82	2.44	2.60	2.11	2.40
Depreciation, amortization and accretion	$ 589,080	$ 562,734	$ 761,718	$ 724,461	$ 671,090	$ 629,896	$ 585,231
Transfers to the Reserve Fund of the City	$ 244,695	$ 232,043	$ 232,043	$ 225,015	$ 218,355	$ 229,913	$ 232,557

Source: Department of Water and Power of the City of Los Angeles.
(1) Derived from the Power System Financial Statements.
(2) Data for the nine-month period ended March 31, 2024 is preliminary and subject to change. Results for the first nine months of Fiscal Year 2023-24 may not be indicative of results for full Fiscal Year 2023-24.
(3) Net of Uncollectible Accounts.
(4) Represents total operating expenses and operating income, excluding depreciation, amortization, accretion and loss on asset impairment and abandoned projects.
(5) Represents change in net position before depreciation, amortization, accretion, interest, extraordinary loss and the Power Transfer.
(6) "Adjusted" indicates measurements of financial and/or operating performance that are not specifically disclosed in the Power System Financial Statements.
(7) Interest expense excluding amortization of debt premium.

Indebtedness

As of September 1, 2024, approximately $11.43 billion in principal amount of debt of the Department payable from the Power Revenue Fund was outstanding. Of such amount, approximately $10.09 billion in principal amount is fixed-rate bonds and approximately $1.34 billion in principal amount is variable-rate bonds. In connection with the Department's five-year capital improvements to the Power System, the Department anticipates that it will issue approximately $8.6 billion of debt through June 30, 2029 payable from the Power Revenue Fund. See "THE POWER SYSTEM – Projected Capital Improvements" and "Note (9) Long-Term Debt" of the Department's Power System Financial Statements.

Certain of the Department's outstanding debt are "federally subsidized direct-pay" bonds, for which, instead of the interest being tax-exempt, the Department receives a subsidy payment from the Treasury Department equal to 35% of the interest paid or up to 70% of the tax credit rate determined by the Treasury Department, depending on the type of federally subsidized direct-pay bonds. Pursuant to certain federal budget legislation adopted in August 2011, starting as of March 1, 2013, the government's subsidy payments were reduced as part of a government-wide "sequestration" of many program expenditures. The amount of the reduction of the subsidy payment has ranged from a high of 8.7% in 2013 to a low of 5.7% for federal fiscal years 2021 through 2031. The amount of this reduction for the Power System has been less than $1.5 million annually and such reductions of approximately $1.2 million annually for the currently outstanding federally subsidized direct-pay bonds are presently scheduled to continue through September 30, 2031.

Congress can terminate, extend, or otherwise modify reductions in subsidy payments due to sequestration at any time. In addition, under the Statutory Pay-As-You-Go Act of 2010, an increase in the federal deficit caused by a new tax or entitlement spending law could trigger further sequestration reductions to non-exempt mandatory spending programs, absent a waiver either as part of the triggering law or in subsequent legislation. If the sequestration reduction rate were to increase to 100%, the reduction in subsidy payments for the Power System would currently be approximately $19.5 million annually.

On May 25, 2023, the Department entered into a revolving credit agreement (the "Wells RCA") with Wells Fargo Bank, National Association ("Wells Fargo") in a principal amount not-to-exceed $300 million outstanding at any one time; provided that the Department can request that Wells Fargo increase the available commitment under the Wells RCA by an additional $200 million, with approval of such increase being at the sole discretion of Wells Fargo. As of September 1, 2024, the Department had no borrowings outstanding under the Wells RCA payable from either the Power Revenue Fund or the Water Revenue Fund. Under the Wells RCA, which expires on May 22, 2026, amounts due may be paid by the Department at any time at its option and in the event of default under the Wells RCA, amounts outstanding would be due immediately. The Department expects to pay principal amounts due under the Wells RCA payable from the Power Revenue Fund from proceeds of subsequent borrowings or from reserves available to the Power System. Amounts borrowed under the Wells RCA payable from the Power Revenue Fund are considered Parity Obligations under the Master Resolution. The Department does not believe that its obligations with respect to the Wells RCA will result in a default under the Department's other Parity Obligations.

For more information about the Department's variable rate bonds, including their associated liquidity facilities (as applicable), see "Note (10) Variable Rate Bonds" of the Department's Power System Financial Statements.

In addition, as of September 1, 2024, the Department was obligated on a "take-or-pay" basis under power purchase or transmission capacity contracts for debt service payments (its share representing approximately $2.88 billion principal amount of bonds) and for operating and maintenance costs of the related projects. The Department has entered into, and may in the future enter into additional, "take-or-pay" contracts in connection with renewable energy projects and other projects undertaken by the joint powers agencies in which it participates. The Department's obligations to make payments under such "take-or-pay" contracts are unconditional payment obligations. See "– Take-or-Pay Obligations" for the "take-or-pay" contracts the

Department has entered as of September 1, 2024. All such commercial paper and "take-or-pay" contract obligations rank on a parity with the Department's Bonds as to payment from the Power Revenue Fund.

Take-or-Pay Obligations

The Department entered into the IPP Contract and the IPP Excess Power Sales Agreement to purchase a share of the output of the IPP. See "THE POWER SYSTEM – Jointly-Owned Generating Units and Contracted Capacity Rights in Generating Units – *Intermountain Power Project*." The Department is also a member of SCPPA and participates in a number of SCPPA projects, including a number of renewable energy projects. See "THE POWER SYSTEM – Renewable Power Initiatives." The Department's obligations to make payments with respect to the IPP and the SCPPA projects in which it participates are unconditional "take-or-pay" payment obligations, obligating the Department to make such payments as operating expenses of the Power System whether or not the applicable project is operating or operable, or the output thereof is suspended, interfered with, reduced, curtailed or terminated in whole or in part. The IPP Contract, the IPP Excess Power Sales Agreement and the agreements with respect to the SCPPA projects (other than with respect to projects in which the Department is the sole participant) contain certain step-up provisions obligating the Department to pay a share of the cost of any deficit in funds for operating expenses, debt service, other costs related to the project and reserves as a result of a defaulting participant. The Department's participation and share of bond debt service obligation (without giving effect to any provisions requiring the Department to contribute to any deficiencies upon default by another participant) as of September 1, 2024, for each of the foregoing projects are shown in the following table:

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POWER SYSTEM
TAKE-OR-PAY OBLIGATIONS FOR BONDS
As of September 1, 2024
(Dollars in Millions)
(Unaudited)

	Principal Amount of Outstanding Debt	Department Participation	Department Share of Principal Amount of Outstanding Debt[6]
Intermountain Power Agency			
IPP	$ 102[1]	48.62%[2]	$ 49[1]
IPP (Renewal Project)	1,531	71.44	1,094
Southern California Public Power Authority			
Mead-Adelanto Transmission Project	14	100.00[3]	14
Mead-Phoenix Transmission Project	11	100.00[3]	11
Linden Wind Energy Project	75	100.00[4]	75
Milford Wind Corridor Phase I Project	65	92.50[5]	60
Milford Wind Corridor Phase II Project	59	100.00[4]	59
Southern Transmission System (STS)	101	59.50[5]	60
STS (Renewal Project)	1,238	90.50[5]	1,120
Windy Point Project	149	100.00[4]	149
Apex Power Project	193	100.00[5]	193
Total	$3,538		$2,884

Source: Department of Water and Power of the City of Los Angeles.

(1) Represents a portion of the IPP and SCPPA debt issued to finance costs of the IPP repowering project and STS renewal project, the Department's share of the bond debt service obligation for which is payable in accordance with the terms of, and the Department's participant share under, the IPP Contract prior to the effective date of the Renewal Power Sales Contract in June 2027. See "THE POWER SYSTEM – Jointly-Owned Generating Units and Contracted Capacity Rights in Generating Units – *Intermountain Power Project*."

(2) Includes the Department's obligations under the IPP Contract (48.617%) but does not include the Department's obligations under the IPP Excess Power Sales Agreement as described under the caption "THE POWER SYSTEM – Jointly-Owned Generating Units and Contracted Capacity Rights in Generating Units – *Intermountain Power Project*."

(3) The bonds remaining outstanding relate to the additional interest acquired by SCPPA solely for the benefit of the Department.

(4) Equals the Department's share of SCPPA's and the City of Glendale's entitlements. See "THE POWER SYSTEM – Renewable Power Initiatives."

(5) Equals the Department's share of SCPPA's entitlement.

(6) In addition to outstanding principal, the Department is obligated to pay its share of interest on outstanding debt and annual operating and maintenance costs. See Note (5) in the Department's Power System Financial Statements for additional information.

Note: Totals may not equal sum of parts due to rounding.

FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY

The following regulatory programs affect the Department and the electric utility industry and should be considered when evaluating the Department. The Department cannot predict at this time whether any additional legislation or rules will be enacted which will affect the Power System's operations, and if such laws or rules are enacted, what the costs to the Department might be in the future because of such action. See "THE DEPARTMENT OF WATER AND POWER OF THE CITY OF LOS ANGELES," "ELECTRIC RATES," "THE POWER SYSTEM – Projected Capital Improvements," "OPERATING AND FINANCIAL INFORMATION" and the Department's Power System Financial Statements for additional information relating to the Department.

California Climate Change Policy Developments

State regulatory agencies such as CARB and the CEC are pursuing a number of regulatory programs designed to reduce GHG emissions and encourage or mandate renewable energy generation. The following is a summary of certain programs. See also "–Environmental Regulation and Permitting Factors" below.

GHG Regulations. In September 2006, the Global Warming Solutions Act was signed into law. This law established the State's target to reduce Statewide GHG emissions back to 1990 levels by 2020, which represented a reduction of approximately 25% Statewide. In September 2016, SB 32, an amendment to the Global Warming Solutions Act, was signed into law, and established a new target to reduce Statewide GHG emissions 40% below 1990 levels by 2030. In September 2022, AB 1279, the California Climate Crisis Act, was signed into law. AB 1279 establishes a State policy to achieve net zero GHG emissions as soon as possible, but no later than 2045, to achieve and maintain net negative GHG emissions thereafter, and to ensure that by 2045, Statewide anthropogenic GHG emission are reduced to at least 85% below the 1990 levels.

CARB implemented the Global Warming Solutions Act through regulations (the "Cap-and-Trade Regulations") that imposed a declining economy-wide limit or cap on GHG emissions from major sources within the State, including the electricity generation industry, and allocates the aggregate emissions limit through the distribution of allowances, or emission credits.

The Cap-and-Trade Regulations require all regulated entities, including the Department, to report annual GHG emissions and to obtain and surrender GHG emission allowances and/or offsets for each metric ton of GHG emissions. Cap-and-trade compliance covers GHG emissions from in-state fossil-fueled power plants, as well as imported electricity from out-of-state resources such as the IPP. In addition, the Department may indirectly bear compliance costs for purchased electricity.

The Department, like other electric utilities, receives an administrative allocation of allowances to cover its expected GHG emissions. Entities that emit GHGs at levels above those for which they receive administrative allocations, if any, must purchase the additional allowances they require at the CARB auctions or from other covered entities with surplus allowances. The Department believes that, if its administrative allowance allocation is not sufficient to cover GHG emissions from all of the Department's generation and purchases of electricity to serve retail customer load, the Department could obtain additional allowances by participating in the CARB auctions or the secondary market. The Department also believes that the cost of compliance with the Cap-and-Trade Regulations for retail customer load will be substantially covered by the administrative allocation of allowances and/or existing rate adjustments and anticipated rate increases through 2030. When the Department sells electricity in the wholesale market, it is required to purchase allowances to cover GHG emissions for those wholesale electricity sales, and the cost of such allowances is included in the electricity price paid by the wholesale buyer.

In July 2017, CARB adopted amendments to the Cap-and-Trade Regulations, which included a 40% reduction in the Statewide GHG emissions cap between 2021 and 2030. CARB granted administrative allowance allocations to electrical distribution utilities such as the Department for the 2021 to 2030 compliance period. The Power System is expected to be able to continue to comply with these amendments with minimal impact to its finances or operations in connection with the implementation of the Power System's resource plan.

In July 2017, AB 398 was signed into law to extend the State's Cap-and-Trade Regulations from 2021 to 2030. The bill cleared both houses with a 2/3 supermajority vote, which protects the legislation from certain legal challenges. Under AB 398, CARB was directed to address the following: establish a price ceiling, offer non-tradeable allowances at two price containment points below the price ceiling, transfer current vintages unsold for more than 24 months to the allowance price containment reserve, evaluate and address allowance overallocation concerns, set industry assistance factors for allowance allocation, and establish allowance banking rules. AB 398 was passed in conjunction with two companion bills: AB 617, which strengthens the monitoring of criteria air pollutants and toxic air contaminants in local communities, and Assembly Constitutional

Amendment No. 1 ("ACA-1"), which created a special Greenhouse Gas Reduction Reserve Fund in the State Treasury, into which all new money collected from the auction of cap-and-trade allowances is to be deposited beginning January 1, 2024 until the effective date of legislation that appropriates money from the fund. The money is then to be appropriated to the existing Greenhouse Gas Reduction Fund, from which money is allocated to 75 California Climate Investment programs administered by 23 State agencies to reduce GHG emission and provide environmental, economic, and public health benefits. A minimum of 35% of California Climate Investments are required to benefit priority populations including disadvantaged communities and low-income communities and households.

In December 2018, CARB approved amendments to the Cap-and-Trade Regulations to make the cap-and-trade program consistent with AB 398 requirements. The amendments to the Cap-and-Trade Regulations went into effect on April 1, 2019. The Department does not expect that its continued compliance with these amendments will have a material adverse effect on the operations or financial condition of the Power System.

In February 2023, CARB issued a market notice regarding further updates to the Cap-and-Trade Regulations. Topics to be considered include banked allowances, evaluation of the program caps within the context of the 2022 Scoping Plan goals, conducting electricity sector and industrial sector leakage studies, updates to offset protocols, addressing the new Extended Day Ahead Market ("EDAM") for electricity, protecting low-income households from disproportionate impacts of energy prices, and carbon dioxide sequestration and removal projects developed under the SB 905 Carbon Capture, Removal, Utilization, and Storage Program. Informal rulemaking activity, including a series of public workshops to discuss potential amendments to the Cap-and-Trade Regulations, commenced in June 2023. The potential amendments of interest to the Department include: revisions (reductions) to the 2025 through 2030 electric utility allowance allocation based on the most recent forecasts and RPS target; requirements for POUs to consign all their allocated allowances to auction similar to investor-owned utilities; the phasing out of the RPS adjustment credit for firmed/shaped electricity imports; how reducing the Cap-and-Trade program allowance budget (the cap) would increase allowance prices; adding the new EDAM to the outstanding emissions leakage calculation; and providing benefits to low-income customers and disadvantaged communities. The Department, individually and in conjunction with the California Municipal Utilities Association ("CMUA") and others, is participating in the rulemaking activities. In April 2024, CARB posted the Standardized Regulatory Impact Assessment ("SRIA") for the Cap-and-Trade Regulations. The SRIA is an initial economic evaluation of potential changes to the cap-and-trade program and is one of the steps CARB must take prior to updating the Cap-and-Trade Regulations. CARB has indicated that the proposed formal rule amendments package is expected to be posted for public review and comment in 2024, and the amendments are anticipated to take effect January 1, 2025.

GHG Emissions Performance Standard and Financial Commitment Limits. Pursuant to SB 1368 (Chapter 598, Statutes of 2006), the CEC adopted a GHG emissions performance standard ("EPS") for electric generating facilities of 1,100 pounds of CO_2 per MWh for "covered procurements" by POUs, such as the Department. SB 1368 also prohibits POUs from making any "long-term financial commitment" in connection with "baseload generation" that does not satisfy the EPS. Generally, a "long-term financial commitment" is any new or renewed power purchase agreement with a term of five years or more, the purchase of an interest in a new power plant or any investment, other than routine maintenance, in an existing power plant that is designed and intended to extend the life of the plant by more than five years or results in an increase of 50 MW or more in its rated capacity. "Baseload generation" means a power plant that is intended to operate at an annualized capacity factor of 60% or more.

California Renewable Portfolio Standard. The State's legislature and executive branch have been active in promoting increasingly stringent renewable energy procurement requirements since 2002. Early efforts established a standard of 20% of renewable electricity generation by 2017. Since then, both legislative and executive branch initiatives have raised that standard in multiple phases.

In April 2011, SBX 1-2, the California Renewable Energy Resources Act, was signed into law. SBX 1-2 established procurement targets for three compliance periods ("Compliance Periods 1 through 3") to be implemented by the procurement plan: 20% of the utility's retail sales were to be procured from eligible renewable energy resources by December 31, 2013; 25% by December 31, 2016; and 33% by December 31, 2020. The Department met the targets established by SBX 1-2 for each of Compliance Periods 1 through 3.

In October 2015, SB 350 was signed into law, which requires retail sellers and POUs, such as the Department, to make reasonable progress each year to ensure it achieves 40% of retail sales from eligible renewable energy resources by December 31, 2024, 45% of retail sales from eligible renewable energy resources by December 31, 2027, and 50% of retail sales from eligible renewable energy resources by December 31, 2030.

In September 2018, SB 100 was signed into law, further increasing statewide RPS targets by requiring retail electric sellers and POUs, such as the Department, to procure a minimum quantity of electricity products from eligible renewable energy resources so that the total kWhs of those products sold to retail end-use customers achieve 44% of retail sales by December 31, 2024, 52% of retail sales by December 31, 2027, and 60% of retail sales by December 31, 2030. In addition, SB 100 establishes that it is the policy of the State that eligible renewable energy resources and "zero-carbon resources" supply 100% of retail sales of electricity to State end-use customers by December 31, 2045. Defining resources that constitute a "zero-carbon resources" will be subject to further regulatory proceedings of the CEC and CARB. The CEC has adopted updates to the RPS Enforcement Procedures for Publicly Owned Utilities which incorporate requirements set forth in SB 350 and SB 100, among other enacted bills. This includes implementing a major provision from SB 350 pertaining to long-term procurement of renewable resources, which requires, beginning January 1, 2021, that at least 65% of RPS procurement must be from contracts of 10 years or more in duration or in ownership or ownership agreements. The updated regulations became effective on July 12, 2021.

In September 2022, SB 1020 was signed into law SB 1020, which revised the policy of the State established by SB 100 to provide that eligible renewable energy resources and "zero-carbon resources" supply 90% of all retail sales of electricity to State end-use customers by December 31, 2035, 95% by December 31, 2040, 100% by December 31, 2045, and 100% of electricity procured to serve all State agencies by December 31, 2035.

See "THE POWER SYSTEM – Renewable Power Initiatives" and "– Projected Capital Improvements" for a description of the Department's existing and potential renewable energy projects.

Biomass Legislation. In September 2016, SB 859 was signed into law. Among other things, SB 859 required certain electric utilities to enter into five-year contracts for at least 125 MW of biomass capacity with facilities that generate energy from feedstock harvested from (a) a byproduct of sustainable forestry management and (b) high fire-hazard zones. Due to the specific requirements of the law, the available facilities satisfying the requirements of the law are limited. The Department, SCPPA and the other POUs procured biomass capacity under contracts from two projects to satisfy the SB 859 requirements: (i) the ARP-Loyalton contract that ended in April 2023, from which the Department's contracted amount was 8.9 MW, and (ii) a contract for 5.4 MW of capacity with Roseburg Forrest Products Co., in Weed, California. See "THE POWER SYSTEM – Renewable Power Initiatives – *Biomass Development*."

Energy Storage Legislation. In October 2017, SB 801 was signed into law, which required the Department, by June 1, 2018, to determine the cost-effectiveness and feasibility of deploying a minimum aggregate total of 100 MW of cost-effective energy storage solutions to help address the Los Angeles Basin's electrical system operational limitations resulting from reduced gas deliverability from the Aliso Canyon natural gas storage facility. Department staff performed analysis and found that a 100 MW battery energy storage system paired with solar generation at the grid would be cost effective by 2022. See "THE POWER SYSTEM – Renewable Power Initiatives – *Energy Storage Development*." To comply with such legislation, the Department has entered into PPAs for energy storage systems at the Eland Solar & Storage Center, Phase 1 and the Eland Solar & Storage Center, Phase 2.

Renewable Energy Policy Development. In August 2018 and March 2019, the CEC adopted the "Toward A Clean Energy Future, 2018 Integrated Energy Policy Report Update" (the "2018 IEPR Update"). The 2018 IEPR Update is composed of two volumes. The first volume (August 2018) is a high-level summary of the energy policies the State has implemented. This high-level summary includes (i) the State's participation in an international pact to reduce emissions and increase renewable electricity procurement to 33% by 2020 and 50% by 2030; (ii) continued support for incentives or mandates for more homes and business to install rooftop solar; (iii) an executive order calling for at least five million zero-emission vehicles on the State's roads by 2030 and an extensive expansion of charging and refueling infrastructure; and (iv) continued support for the development and implementation of an energy efficient program in existing buildings. The second volume (March 2019) provides updated analysis of issues raised in previous Integrated Energy Policy Reports, including "advancing then-Governor Brown's call to expand state adaptation activities through Executive Order B-30-15, with the goal of making the consideration of climate change a routine part of planning," as well as, "enhancing the resiliency of the electricity system while integrating increasing amounts of renewable energy." See "– Environmental Regulation and Permitting Factors – *Water Quality – Cooling Water Process – State Water Resources Control Board*" below.

Legislation and Court Action Relating to Wildfires. In September 2016, SB 1028 was signed into law. SB 1028 requires each POU, including the Department, each IOU and each electric cooperative in the State to construct, maintain, and operate its electrical lines and equipment in a manner that will minimize the risk of catastrophic wildfire posed by those electrical lines and equipment. SB 1028 required the governing board of each POU to make an initial determination of whether its overhead electric lines and equipment pose a significant risk of catastrophic wildfire based on historical fires and local conditions. POU governing boards were required to independently make this determination based on all relevant information, including the CPUC's Fire Threat Map which was adopted by the CPUC in January 2018 (discussed below). On September 5, 2018, the Board determined that the Power System's overhead electrical lines and equipment do not pose a significant risk of causing a catastrophic wildfire. Prior to the enactment of SB 1028, the Department has had an active fire prevention plan since 2008, which includes construction standards, a vegetation management program, and an inspection and maintenance program.

SB 901, which was signed into law in September 2018, amends certain provisions of SB 1028. Under SB 901, among other things, POUs, such as the Department, are required to prepare a wildfire mitigation plan, initially before January 1, 2020, and annually thereafter. SB 901 requires the POU to contract with a qualified independent evaluator to review and assess the comprehensiveness of its plan. The report of the independent evaluator is to be made available to the public and presented at a public meeting of the POU's governing board. Consistent with the requirements of SB 901 and subsequent legislation (AB 1054 discussed below), the Department updates its wildfire mitigation plan on an annual basis, with comprehensive revisions and independent evaluator reviews occurring every three years.

In 2017, the CPUC adopted a work plan for the development and adoption of the CPUC Fire-Threat Map. On the CPUC Fire-Threat Map, any area in a Tier 2 fire-threat area is depicted as an "elevated risk (including likelihood and potential impacts on people and property) from utility associated wildfires" and any area in a Tier 3 fire-threat area is depicted as an "extreme risk (including likelihood and potential impacts on people and property) from utility associated wildfires." Based on the Department's wildfire mitigation plan dated June 2024, approximately 13.8% of the Power System's overhead distribution power lines fall within a Tier 2 area and approximately 0.5% of the Power System's overhead distribution power lines fall within a Tier 3 area. The Department has not modeled a total destruction scenario in Tier 2 and Tier 3 areas of its service territory because such areas represent a small portion of the Power System's service territory; but the Department believes that based on the low density of the property in the applicable Tier 2 and Tier 3 areas, the potential property damage is expected to be relatively low. In these applicable Tier 2 and Tier 3 areas, the Department continues to replace wooden pole assets with alternative material poles, install covered conductors where feasible, equip poles for high wind load in order to resist fire damage, and employ a robust vegetation management program to further mitigate wildfire risk exposure.

AB 1054 was signed into law by Governor Newsom in July 2019. AB 1054 requires POUs to submit their wildfire mitigation plans for annual review to a newly created California Wildfire Safety Advisory Board (the "CWSAB"), with comprehensive revisions submitted every three years. The Department's 2023 wildfire mitigation plan was a comprehensive update, meeting the requirements of AB 1054. On December 4, 2023, the CWSAB published its guidance advisory opinion for the POU-submitted 2023 wildfire mitigation plans. The CWSAB's advisory opinion to each POU was to embark on a collaborative approach as set forth in the advisory opinion designed to improve POU reporting on its wildfire prevention efforts and the CWSAB's ability to comprehend and advise on those reports. Previous reviews by the CWSAB found the Department's wildfire mitigation plan to be comprehensive with clear descriptions of its relevant programs. The Department has actively participated in the CWSAB's meetings to discuss updates to POU wildfire mitigation plans. The Department was required to submit its 2024 annual update to the Department's wildfire mitigation plan to the CWSAB by July 1, 2024. The Department continues to submit its wildfire mitigation plan to the CWSAB on an annual basis, with the last submittal occurring on June 27, 2024, in satisfaction of the requirement. The Department is required to submit its next annual update to the Department's wildfire mitigation plan by July 1, 2025.

AB 1054 also establishes a new wildfire fund for IOUs to pay for eligible, uninsured third-party damage claims arising from future covered wildfires. Participation in the wildfire fund is exclusive to IOUs. Each of the major IOUS in California are now participating in the Wildfire Fund. POUs, such as the Department, are not eligible to participate in or receive funding for wildfire claims from the Wildfire Fund.

A number of wildfires occurred in the State in the last several years. Under the doctrine of inverse condemnation (a legal concept that entitles property owners to just compensation if their property is damaged by a public use), California courts have imposed liability on utilities in legal actions brought by property holders for damages caused by such utilities' infrastructure. Thus, if the facilities of a utility, such as its electric distribution and transmission lines, are determined to be the substantial cause of a fire, and the doctrine of inverse condemnation applies, the utility could be liable for damages without having been found negligent. In August 2019, in its decision in the case of *City of Oroville v. Superior Court of Butte County*, No. S243247 (Cal. Aug. 15, 2019) involving damages related to sewage overflows from a city sewer system, the California Supreme Court issued a rare but narrow decision regarding inverse condemnation liability. The residential property owner in that case failed to install a mandatory sewer backflow device, allowing the court to conclude the absence of that device was the substantial cause of the damages to the residence. The property owner was unable to prove the property damage was the probable result or necessary effect of an inherent risk associated with the design, construction or maintenance of the relevant public improvement. SB 1028, SB 901 and AB 1054 do not address existing legal doctrine relating to utilities' liability for wildfires. How any future legislation or judicial decisions address the State's inverse condemnation and liability issues for utilities in the context of wildfires in particular could be significant for the electric utility industry, including the Department.

See "LITIGATION – Wildfire Litigation" for information about current litigation regarding wildfires and "THE DEPARTMENT – Insurance" for information about the Department's current insurance coverage for wildfires.

Environmental Regulation and Permitting Factors

General. Numerous environmental laws and regulations affect the Power System's facilities and operations. The Department monitors its compliance with laws and regulations and reviews its remediation obligations on an ongoing basis. The following topics highlight some of the major environmental compliance issues affecting the Power System:

Air Quality – Nitrogen Oxide (NOx) Emissions. The Department's four Los Angeles Basin power plants are subject to the Regional Clean Air Incentives Market ("RECLAIM") NOx regulations adopted by the SCAQMD. In accordance with these regulations, SCAQMD established annual NOx allocations for stationary source facilities based on historical emissions with a declining emissions cap. These allocations are in the form of RECLAIM trading credits ("RTCs"). Facilities can comply with RECLAIM by purchasing RTCs from the RECLAIM market, installing emission controls, and/or reducing operations. The Department has installed emission control equipment at its power plants to reduce NOx emissions. The Los Angeles Basin Stations are all equipped with emission control equipment. As a result of the installation of NOx control equipment and the modernization of existing electric generating units, the Department has had sufficient RTCs to meet its native load requirements for normal operations under the NOx RECLAIM regulation.

In March 2017, the SCAQMD adopted the 2016 Air Quality Management Plan and included a control measure to achieve an additional five tons per day NOx reduction as soon as feasible but no later than 2025, and to transition the RECLAIM program to a command-and-control regulatory structure requiring Best Available Retrofit Control Technology ("BARCT") as soon as feasible.

In July 2017, AB 617 was signed into law, which addresses criteria pollutants (including NOx) and toxic air contaminants at stationary sources. RECLAIM facilities are subject to the BARCT requirements of AB 617.

The market-based RECLAIM program is being transitioned to a command-and-control regulatory structure. The RECLAIM program was originally scheduled to end on December 31, 2023 but is now expected to extend past 2025 after the EPA's approval of the State Implementation Plan and the resolution of outstanding issues with the New Source Review ("NSR") Program. The Los Angeles Basin Stations will transition from RECLAIM to a source-specific NOx rule for electric generating units that will include NOx limits reflecting BARCT. SCAQMD Rule 1135, the "command-and-control" rule for electric generating units, was adopted in November 2018. Instead of receiving an annual allocation of emission credits, electric generating units will be required to meet a NOx emission limit. The NOx emission limit for simple cycle gas turbines is 2.5 parts per million ("ppm") while the NOx emission limit for combined cycle gas turbines is 2.0 ppm. Failure to meet the NOx limits by the December 31, 2023 compliance date would prohibit out-of-compliance generating units from operating. To comply with the SCAQMD Rule 1135 NOx limit of 2.5 ppm for simple cycle gas turbines, the existing selective catalytic reduction equipment for the Department's simple cycle combustion turbines at the Harbor Generating Station and the Valley Generating Station were tuned. To meet the SCAQMD Rule 1135 NOx limit of 2.0 ppm for combined cycle gas turbines, the combustors of the combined cycle gas turbines at the Harbor Generating Station were upgraded with dry low NOx combustors. The upgrade of the Harbor Generating Station's combined cycle gas turbine combustors began construction in October 2023 and completed commissioning in April 2024. The Harbor Generating Station's combined cycle unit is currently operational and is in compliance with the Rule 1135 NOx emission limit since its return to service in April 2024. The Department does not expect the modifications to have a material adverse effect on the operations or financial condition of the Power System. The remaining electric generating units at the Los Angeles Basin Stations either already meet the NOx limits or are exempt from the rule. On January 7, 2022, Rule 1135 was amended to reference startup and shutdown provisions as defined in SCAQMD Rule 429.2, which establishes requirements during startup and shutdown and exempts units regulated under Rule 1135 from NOx emission limits during startup and shutdown.

Regulatory Actions Under the Clean Air Act. The United States Environmental Protection Agency (the "EPA") regulates GHG emissions under existing law by imposing monitoring and reporting requirements, and through its permitting programs. Like other air pollutants, GHGs are regulated under the Clean Air Act through the Prevention of Significant Deterioration ("PSD") Permit Program and the Title V Permit Program. A PSD permit is required before commencement of construction of new major stationary sources or major modifications of a major stationary source and requires best available control technologies to control emissions from the new or modified stationary source. Title V permits are operating permits for major sources that consolidate all Clean Air Act requirements (arising, for example, under the Acid Rain, New Source Performance Standards, National Emission Standards for Hazardous Air Pollutants, and/or PSD programs) into a single document and the permit process provides for review of the documents by the EPA, state agencies and the public. GHGs from major natural gas-fired facilities are regulated under both permitting programs through performance standards imposing efficiency and emissions standards.

In May 2023, the EPA proposed new carbon pollution standards for coal and natural gas-fired power plants. As originally proposed, the rule would establish CO_2 emissions limits and guidelines for new gas-fired combustion turbines, existing coal, oil and gas-fired steam generating units, and certain existing gas-fired combustion turbines. The proposal included the following elements, in each case reflecting the application of best systems for emissions reduction ("BSER"), taking into account costs, energy requirements and other statutory factors: (i) strengthening the current New Source Performance Standards for newly built fossil fuel-fired stationary combustion turbines (generally natural gas-fired); (ii) establishing emission guidelines for carbon pollution from existing fossil fuel-fired steam generating units (including coal, oil and natural gas-fired units) beginning January 1, 2030; and (iii) establishing emission guidelines for large, frequently used existing fossil fuel-fired stationary combustion turbines (generally natural gas-fired) beginning January 1, 2032 or January 1, 2035, depending on which BSER technology is pursued. Under the proposed rule, emissions standards are established for different subcategories of power plants according to unit characteristics such as their capacity, their intended length of operation, and/or their frequency of operation. The proposed rule would generally require more CO_2 emissions control at fossil fuel-fired power plants that operate more frequently and for more years and would phase in increasingly stringent CO_2 requirements over time. The standards would be based on emission control methods that can be installed at the plants, including technologies such as carbon capture and sequestration/storage ("CCS"), low-GHG hydrogen co-firing, and natural gas co-firing; however, the determination of whether to implement such technologies or to comply with the proposed emissions limits by other means would be made by power plant operators and state regulators. Under the proposal, states would be required to submit compliance plans to the EPA within 24 months of the effective date of the adoption of the regulations. The Department participated in the rulemaking process.

In February 2024, the EPA announced that it would remove the elements that would have applied to existing natural gas-fired power plants from the final version of the rule. Instead, the EPA stated that it will commence a new rulemaking process that will apply to existing natural gas-fired plants and regulate additional pollutants. On March 26, 2024, the EPA opened a non-regulatory docket which includes key framing questions intended to help the EPA develop standards for reducing GHG emissions and possibly criteria pollutant emissions from existing gas combustion turbines in the power sector. Comments from stakeholders were accepted by the EPA through May 28, 2024.

On April 25, 2024, the EPA released the final rule for existing coal-fired and new natural gas-fired power plants that is designed to ensure that all coal-fired plants that plan to run in the long-term and all new baseload gas-fired plants control 90% of their carbon pollution. The IPP coal units and other existing coal-fired plants that plan to cease operations prior to January 2032 will not be subject to emission reduction obligations under the final rule. The IPP natural gas units, however, will be subject to the separate rule being developed for existing gas units. Under the final rule, for new baseload combustion turbines, the emission guidelines are based on BSER, which the EPA determined to be CCS. Under the final rule, new combustion turbines with a capacity factor of 40% or more are considered to be baseload turbines which are subject to a CO_2 emission standard of 100 lb. CO_2/MWh based on 90% capture of CO_2, starting on January 1, 2032. Prior to 2032, the emission standard is between 800 to 900 lb. CO_2/MWh depending on the size of the unit. Intermediate turbines with a capacity factor between 20% and 40% will be subject to a standard of 1,170 lb CO_2/MWh, which is based on efficient operation of simple cycle turbines. Low load turbines with a capacity factor of less than 20% are subject to a standard of 120-160 lb. CO_2/MMBtu, based on use of low-emitting fuel (clean hydrogen, natural gas and/or distillate oil). The standards under the final rule are technology-neutral, therefore allowing the affected sources to comply with the emission standard through hydrogen co-firing. For existing oil and natural gas-fired steam electric generating units, standards are based on routine operation and maintenance with different levels of stringency based on the capacity factor. The emission standard for natural gas-fired units with a capacity factor of less than 8% is 130 lb. CO_2/MMBtu. Intermediate units with capacity factor of 8 to 45% are subject to an emission standard of 1,600 lb. CO_2/MWh while baseload units with capacity factor of 45% or more must comply with an emission standard of 1,400 lb. CO_2/MWh.

See also "THE POWER SYSTEM – General," "– Department-Owned Generating Units," "– Jointly Owned Generating Units and Contracted Capacity Rights in Generating Units," "– Projected Capital Improvements," "– Energy Efficiency" and "– Renewable Power Initiatives."

Air Quality – Mercury. The Clean Air Act provides for a comprehensive program for the control of hazardous air pollutants ("HAPs"), including mercury. In February 2012, the EPA finalized a rule called the Mercury and Air Toxics Standards ("MATS") to reduce emissions of toxic air pollutants, including mercury, from coal- and oil-fired electric generating units, and subsequently amended the rule in 2013 and 2014. The MATS rule set technology-based emission limitation standards for mercury and other toxic air pollutants, based upon reductions available through the use of "maximum achievable control technology" at coal- and oil-fired electric generating units. The rule has minimal impact to IPP, the one remaining coal-fired plant that is a source of energy for the Department. IPP did not have to install control technology and EPA has deemed the IPP units as low-emitting electric generating units ("LEEs"). IPP is subject to periodic testing, work practice standards and recordkeeping requirements.

The State of Utah adopted minimum performance criteria for existing electric generating units and offset requirements for potential increases in mercury emissions from new or modified electric generating units. Utah's minimum performance criteria include a rule, effective January 1, 2012, that coal-fired power plants, such as IPP, meet a mercury emissions limit of 0.00000065 lb/MMBtu or have at least a 90% mercury removal efficiency. IPP complies with the Utah mercury standard.

In April 2023, the EPA published its proposed rule entitled "National Emission Standards for Hazardous Air Pollutants ("NESHAPs"): Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review." The proposed rule establishes a lower mercury emissions standard for lignite coal, which does not apply to IPP. The rule also proposes to reduce the emissions standard for filterable particulate matter ("fPM") from 0.03 lb./MMBtu to 0.01 lb./MMBtu. In addition, it requires the owners and operators of existing coal-fired plants to only use a continuous emissions monitoring system ("CEMS") to demonstrate compliance with the new fPM standards. The EPA requested comments on the proposed rule, as well as on the possibility of reducing the compliance timeframe from three years to one year from the effective date.

On April 25, 2024, the EPA released the final NESHAPs rule (also referred to as the MATs rule) which finalizes the proposed change to the fPM emission standard from 0.03 lb./MMBtu to 0.01 lb./MMBtu. The final rule also requires that existing coal and oil-fired units utilize CEMS to demonstrate compliance with the fPM emission standard. The compliance date for affected coal-fired sources to comply with the revised fPM limit is three years after the effective date of the final rule. With IPP replacing the coal units with natural gas-fired units by 2025, IPP will not be subject to the more stringent requirements under the final MATS rule.

SCAQMD Air Quality Management Plan. The SCAQMD periodically prepares an overall plan, known as an Air Quality Management Plan (the "AQMP"), which include control measures to meet federal air quality standards and incorporate the latest technical planning information. The AQMP is a regional and multi-agency effort. In 2021, the Department participated in the stakeholder working group meetings dedicated to the development of the 2022 AQMP and the rules and rule amendments to implement the control measures included in the 2022 AQMP that could potentially impact the Department's operations. In December 2, 2022, the SCAQMD Board approved the 2022 AQMP, which aims for a 45% reduction in NOx emissions through this plan. In January 2023, CARB adopted the SCAQMD 2022 AQMP, and directed staff to submit the 2022 AQMP to the EPA as a revision to the California State Implementation Plan to achieve the federal air quality standard for ozone. As called for in the 2022 AQMP, SCAQMD has initiated separate rulemaking processes addressing the different proposed control measures cited in the AQMP, which are ongoing.

Water Quality – Cooling Water Process.

General. A cooling process is necessary for nearly every type of steam turbine electrical generating station. Once-through-cooling is the process where water is drawn from a source, pumped through equipment at a power plant to provide cooling and then discharged. In once-through-cooling, the water is not chemically changed in the cooling process; however, the water temperature can increase. The water drawn into the intake and the thermal discharges are regulated by the federal Clean Water Act and similar state law.

EPA Requirements. A final regulation implementing Section 316(b) of the Clean Water Act ("Rule 316(b)") addresses the impacts of water intake by once-through-cooling systems. Rule 316(b) affects intake structures for power generating facilities that withdraw more than two million gallons per day for cooling purposes. The Department has determined it will comply with impingement mortality ("IM") and entrainment mortality ("EM") by replacing once-through-cooling with other technology by the deadline of 2029 negotiated with the SWRCB.

State Water Resources Control Board. The SWRCB established a separate statewide policy with respect to the Clean Water Act Section 316(b) in 2010 published as Section 2922 of Title 23 of the California Code of Regulations ("Regulation Section 2922"). The regulation generally requires all facilities subject to the Clean Water Act Section 316(b) to either use closed cycle cooling or flow reduction commensurate to that of wet closed cycle. The Department owns three coastal generating stations that utilize once-through-cooling, that provide approximately 85% of the Department's in-basin generation and 39% of the total generating plant capacity owned by the Department, which are subject to Regulation Section 2922.

In July 2011, the SWRCB adopted an amendment to Regulation Section 2922 that accelerated the compliance dates for three coastal units and extended the compliance dates until 2024 for two coastal units and 2029 for the remaining four coastal units. In August 2023, the SWRCB adopted another amendment, extending the compliance date for the two units with a December 31, 2024 deadline to December 31, 2029. The new compliance schedule allows for both grid reliability and a financially sustainable path forward while making the equipment upgrades necessary to remove the coastal generating stations' units from utilizing once-through-cooling, shifting the focus from repowering to clean energy alternatives.

Regional Requirements – Thermal Discharges at Harbor Generating Station and Haynes Generating Station. The SWRCB's Water Quality Control Plan for Control of Temperature in the Coastal and Interstate Waters and Enclosed Bay and Estuaries of California (the "California Thermal Plan") has different thermal criteria for discharges into estuaries and bays than it does for discharges into the ocean. The water discharges from Harbor Generating Station and Haynes Generating Station were originally permitted as ocean discharges. In January 2003, however, the Los Angeles Regional Water Quality Control Board ("LARWQCB") informed the Department that it (i) reclassified the Harbor Generating Station discharge as an enclosed bay discharge and that (ii) it intends to reclassify the Haynes Generating Station discharge as an estuary discharge during the next permit renewal. The Harbor Generating Station NPDES permit was renewed by the LARWQCB in July 2003, with the new enclosed bay classification and the associated, more stringent, permit limits. Based on the notice of intent to reclassify the Haynes Generating Station discharge and planned changes to be made to the Haynes Generating Station's flow volume, the Department has completed a hydrological model of the Lower San Gabriel River. Haynes discharges into the San Gabriel River, which in turn flows into the ocean. The hydrological study concluded that the estuary classification does not reflect current site conditions with the operation of the existing power plants. However, the LARWQCB stated that for regulatory purposes, the Lower San Gabriel River would likely represent an estuary. With this designation, the Haynes Generating Station would be unable to comply with the California Thermal Plan and other permit conditions without a permit variance. If the Department is unable to obtain a permit variance, the Haynes Generating Station facility could be limited or unable to operate. The LARWQCB has recognized the need to continue utilizing once-through cooling at the Haynes Generating Station through 2029 for electric grid reliability and is currently working with the Department on a solution for all discharge issues associated with the estuary designation, which could include the issuance of a variance or time schedule order (TSO).

Superfund. The federal Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended, as well as State statutes, impose strict liability for cleanup costs upon those who generate or dispose of hazardous substances and hazardous wastes. The Department's past disposal practices may result in Superfund liability as previously approved disposal methods or sites become candidates for Superfund classification. In addition, under these statutes, the Department may be held liable for cleanup activities on property that it owns and operates, even if the conditions requiring cleanup existed before the Department's occupancy of a site. As a result, the Department may incur substantial, but presently unknown, costs as a participant in the cleanup of sites contaminated with hazardous substances or wastes.

Coal Combustion Residuals. In April 2015, the EPA promulgated the final coal combustion residuals ("CCR") rule, which regulates the disposal and management of CCRs as non-hazardous under Subtitle D of the Resource Conservation and Recovery Act ("RCRA"). The final CCR rule became effective in October 2015.

Under the CCR rule, existing impoundments for managing CCR must either cease accepting CCR materials as of the rule's effective date, or implement a variety of measures to ensure that such facilities will not result in releases to the environment. One such requirement is that all such facilities be retrofitted with liners that are intended to prevent the migration to groundwater of contaminants found in CCR. In addition, the rule requires monitoring of groundwater to determine whether releases have occurred, and to contain or clean up any such releases that are discovered.

The IPP utilizes impoundments (ponds and landfills) for the management of CCR that are subject to the CCR rule. The IPP has met all interim compliance requirements for the new CCR rule including: setting up a public website and posting CCR operating records, developing new groundwater monitoring wells and sampling plans, beginning to sample groundwater wells quarterly, and developing and implementing a fugitive dust monitoring plan.

The Department believes that the IPP's CCR management facilities may not meet the design criteria required for surface impoundments and that releases of certain contaminants have occurred from the current, unlined impoundments. The Department understands that IPA has made notification that IPP will cease operations of the coal-fired boilers and switch to another fuel source for generation by 2028.

The Department has estimated the IPP's total cost of compliance with the final CCR rule to fall within the range of $55 million to $70 million (in 2019 dollars) over a time period commencing in 2019 and ending between approximately 2025 and 2028 (except for long-term monitoring and maintenance, which would last approximately 30 years after closure). Of this total cost, the Power System would be responsible for a percentage equal to its total use of energy produced by IPP. For more information about IPP, see "THE POWER SYSTEM – Jointly-Owned Generating Units and Contracted Capacity Rights in Generating Units – *Intermountain Power Project*."

In November 2019, the EPA proposed revisions (Part A) to the CCR rule. The proposed revisions focus on closure requirements for impoundments and landfills. IPA is opting to comply with the alternate closure requirement as currently described in the current CCR rule. The proposed revisions include additional requirements to get approval of the EPA or the state to close impoundments in accordance with alternate closure procedures. There is also a new requirement to prepare a plan to mitigate potential risk to human health and environmental from CCR surface impoundments. The Part A revisions were finalized and published in the Federal Register in August 2020. IPP submitted a request to the EPA demonstrating that they meet the alternate closure procedures as described in the regulations. The EPA confirmed that IPP's demonstration was complete on January 11, 2022; however, as of July 2024, the EPA has not yet made a substantive determination on IPP's demonstration submission. Nonetheless, the April 2021 cease operation of the impoundments is tolled under the regulations because the IPP submitted a timely demonstration.

In February 2020, the EPA proposed a federal CCR permit program. Currently, the CCR rule is self-implementing and is enforced primarily though citizen suits which are decided in federal district courts. This program will not change the provisions of the regulations but the EPA will be able to review, approve, issue, and enforce the CCR regulations through the permit program.

In March 2020, the EPA proposed more revisions (Part B) to the CCR rule including provisions to demonstrate equivalent alternate liners, using CCR for closing impoundments, and completion of closure by removal during post closure care period. The proposed revisions do not impact IPA's plan to follow alternate closure requirements. On April 25, 2024, the EPA released a final rule on the proposed closure option for units being closed by removal of CCR. The EPA is still considering other provisions from the proposed revisions that were not addressed in the final rule and may be addressed in a subsequent action.

Utah Senate Bill 161. The Utah Legislature enacted Utah Senate Bill 161 ("Utah S.B. 161") in its 2024 General Session, which became effective on May 1, 2024. The reported purpose of Utah S.B. 161 was to induce IPA to amend IPA's environmental permits to provide for the operation of at least one of the IPP coal-fired units after July 1, 2025, the date by which IPA has committed to cease operation of the IPP coal units permanently. Utah S.B. 161 also required IPA to grant an option to the State of Utah for the purchase of at least one of the IPP coal-fired units with such option to be effective for two years starting on July 2, 2025. Following the enactment of Utah S.B. 161, the governor of Utah called a special session of the Utah Legislature resulting in the enactment of Utah House Bill 3004 ("Utah H.B. 3004"), which became effective on June 21, 2024. Utah H.B. 3004 repealed the provisions of Utah S.B. 161 relating to IPA amending its environmental permits. IPA continues, however, to be obligated to provide the purchase option to the State with respect to one of the IPP coal-fired units. Utah H.B. 3004 also directs a state agency, the Decommissioned Asset Disposition Authority (the "Utah Disposition Authority"), to submit an application to amend IPA's air permit to allow for a coal unit to operate after July 1, 2025. Utah H.B. 3004 also directs environmental regulators in the State of Utah to determine whether such an application would be granted if submitted by IPA. The Utah Disposition Authority has also been directed to determine the regulatory and commercial feasibility of operating an IPP coal unit after July 1, 2025, and to conduct a process for soliciting bids from qualified purchasers for the coal unit.

Prior to the enactment of H.B. 3004, IPA stated that Utah S.B. 161 purported to create obligations for IPA that are inconsistent with IPA's obligations under federal regulations and the IPP construction and operating permits issued under federal law; and that if IPA complied with Utah S.B. 161, as originally enacted, IPA may be subject to enforcement actions that could result in IPA being required to cease operation of the IPP coal units prior to the scheduled commercial operation date of the IPP repowering project and that may interfere with the construction and operation of the IPP repowering project. In public testimony with respect to Utah H.B. 3004, IPA management stated that the new bill made some important adjustments to the legislation and moved things in the right direction. IPA has indicated that it is still working to determine the impact of Utah S.B. 161, as modified by Utah H.B. 3004, and to identify the appropriate course of action in response to the recent enactments. The Department cannot predict the impacts of the new legislation on the operation of IPP or the construction and operation of the IPP repowering project.

Electric and Magnetic Fields. A number of studies have been conducted regarding the potential long-term health effects resulting from exposure to electric and magnetic fields created by high voltage transmission and distribution equipment. Additional studies are being conducted to determine the relationship between electric and magnetic fields and certain adverse health effects, if any. At this time, it is not possible to predict the extent of the costs and other impacts, if any, which the electric and magnetic fields concerns may have on electric utilities, including the Department.

For additional information regarding environmental matters, see "THE POWER SYSTEM – Jointly-Owned Generating Units and Contracted Capacity Rights in Generating Units – *Hoover Power Plant – Environmental Considerations" and " – Palo Verde Nuclear Generating Station – Nuclear Waste Storage and Disposal.*"

Energy Regulatory Factors

Developments in the California Energy Market. In the late 1990s, the State restructured its electricity market so that regulated retail suppliers were required to purchase their customers' supply needs through a centralized, wholesale market. During portions of 2000 and 2001, wholesale market prices in the State became highly volatile. The volatility in wholesale prices that the State experienced in 2000 and 2001 was due to a number of factors, including flaws in the structure of the wholesale market and unlawful manipulation of the wholesale market. As discussed below, the wholesale market in the State has since been redesigned, and Congress has established mechanics for policing wholesale markets.

Volatility in electricity prices in the State may nevertheless return due to a variety of factors that affect the supply and demand for electric energy in the western United States. These factors include, but are not limited to, the adequacy of generation resources to meet peak demands, the availability and cost of renewable energy, the impact of GHG emission legislation and regulations, fuel costs and availability, weather effects on customer demand, the impact of climate change, wildfire mitigation and potential liability cost recovery, insurance costs, transmission congestion, the strength of the economy in the State and surrounding states and levels of hydroelectric generation within the region (including the Pacific Northwest). Volatility in electricity prices may contribute to greater volatility in the Power System's Power Revenue Fund from the sale (and purchase) of electric energy and, therefore, could materially affect the financial condition of the Power System. To mitigate price volatility and the Department's exposure on the spot market, the Department undertakes resource planning activities and plans for its resource needs. Of particular note, the Department has power supply contracts and other arrangements relating to its system supply of power that are of specified durations. See "THE POWER SYSTEM – Generation and Power Supply."

Energy Policy Act of 1992. The Energy Policy Act of 1992 ("EPAct 1992") made fundamental changes in federal regulation of the electric utility industry, particularly in the area of transmission access under sections 211, 212 and 213 of the Federal Power Act, 16 U.S.C. § 791a et seq. The purpose of these changes, in part, was to bring about increased competition among wholesale suppliers. As amended, sections 211, 212 and 213 authorize FERC to compel a transmission provider to provide transmission service upon application by an electricity supplier. FERC's authority includes the authority to compel the enlargement of transmission capacity as necessary to provide the service. The service must be provided at rates, charges, terms and conditions that are set by FERC. Electric utilities that are owned by municipalities or other public agencies are "transmitting utilities" that may be subject to an order under sections 211, 212 and 213. EPAct 1992 prohibits FERC from requiring "retail wheeling" under which a retail customer that was located in one utility's service area could obtain electricity from another source. An order by FERC to provide transmission might adversely affect the Power System by, and among other things, increasing the Department's cost of owning and operating transmission facilities and/or by reducing the availability of the Department's transmission resources for the Department's own use.

Energy Policy Act of 2005. The Energy Policy Act of 2005 ("EPAct 2005") addresses a wide array of matters that affect the entire electric utility industry, including the Department.

Subject to certain conditions and limitations, EPAct 2005 authorizes FERC to require an unregulated transmitting utility such as the Department to provide electric transmission services at rates that are comparable to those that the unregulated transmitting utility charges itself; and on terms and conditions (not relating to rates) that are comparable to those under which the unregulated transmitting utility provides transmission services to itself and that are not unduly discriminatory or preferential. FERC may compel open access in this context unless the order would violate a private activity bond rule for purposes of section 141 of the Code (as defined below). To date, FERC has chosen to exercise its authority on a case-by-case approach. Additionally, FERC has the authority to require the provision of transmission services in response to specific requests for service. See ELECTRIC RATES – Rate Regulation. Furthermore, should the Department purchase transmission services from a public utility, as defined in the Federal Power Act, pursuant to the terms and conditions of FERC's *pro forma* OATT, the *pro forma* OATT requires the Department to provide the transmission provider it is purchasing transmission services from, comparable transmission service that it is capable of providing on similar terms and conditions over facilities and for the transmission of electric energy.

EPAct 2005 provides for criminal penalties for manipulative energy trading practices.

EPAct 2005 repealed the Public Utility Holding Company Act of 1935, which prohibited certain mergers and consolidations involving electric utilities. EPAct 2005 gives FERC and state regulators access to books and records within holding companies that include regulated public utilities. In addition, FERC may oversee inter-affiliate transactions within such holding company systems. These provisions of EPAct 2005 are referred to as "PUHCA 2005." PUHCA 2005 does not apply to the Department but generally accommodates more combinations of assets within the electric utility industry.

EPAct 2005 requires the creation of national and regional electric reliability organizations to establish and enforce, under FERC's supervision, mandatory standards for the reliable operation of the bulk power system. The standards are designed to increase system reliability and to minimize blackouts. FERC has designated NERC as the national electric reliability organization. FERC has designated WECC as the regional reliability organization for utilities in the West, including the Department. Failure to comply with NERC and WECC standards exposes a utility such as the Department to penalties. NERC and WECC audit the Department's compliance with the reliability standards once every three years and, as indicated above, impose penalties for non-compliance. The Department has from time to time fallen short in meeting its regulatory and reporting requirements on a timely basis and either has self-reported or responded to audit findings from WECC. The Department does not believe that pending reporting and audit matters will have a material adverse effect on the Department's operations or financial position.

Under EPAct 2005, State IOUs were required to offer, to each of their classes of customers, a time-based rate schedule that would enable customers to manage their energy use through advanced metering and communications technology.

EPAct 2005 authorizes FERC to compel the siting of certain transmission lines if FERC determines that a state has unreasonably withheld approval.

EPAct 2005 promotes increased imports of liquefied natural gas and includes incentives to support the development of renewable energy technologies. EPAct 2005 also extends for 20 years the Price-Anderson Act, which provides certain protection from liability for nuclear power issues and provides incentives for the construction of new nuclear plants.

FERC Order 1920. On May 13, 2024, FERC issued Order 1920 to reform the planning of the nation's transmission system as well as the allocation of costs for new transmission projects. Order 1920, among other things, requires public utility (jurisdictional) transmission providers to conduct and periodically update long-term regional transmission planning to anticipate future needs, consider a broad set of benefits when planning new facilities, identify opportunities to modify in-kind replacement of existing transmission facilities to increase their transfer capability, propose methods of cost allocation to pay for selected long-term regional transmission facilities, and increase transparency regarding local transmission planning information. Order 1920 expands the role of states throughout the process of planning, selecting and determining how to pay for new transmission facilities. Order 1920 reflects input FERC sought from interested parties on a variety of reforms aimed at expanding the nation's transmission grid to accommodate the surge of renewable generation expected in the next two decades to achieve aggressive decarbonization goals of the Biden Administration and many states. As a municipal utility actively participating in the WestConnect regional transmission planning process, the Department has expressed its support of long-term regional transmission planning and its intent, in collaboration with WestConnect, to adhere to the principles of Order 1920. The Department is evaluating the implications of Order 1920 with respect to the transmission planning processes of the Power System.

Future Regulation of the Electric Utility Industry. The electric utility industry is highly regulated and is also regularly subject to reform. The most recent reforms and proposals are aimed at reducing emissions of GHGs from combustion of fossil fuels and reducing impacts from using ocean water for power plant cooling. The Department is unable to predict future reforms to the electric utility industry or the ultimate impact on the Department of recent reforms and proposals. In particular, the Department is unable to predict the outcome of proposals on reducing GHG emissions and the associated impact on the operations and finances of the Power System or the electric utility industry.

Security of the Power System

The Department has a variety of physical security measures in place, as well as a cybersecurity program, aimed at protecting the assets of the Power System and the technological systems utilized in the delivery of electric power service to its customers. The Department operates a 24/7 operations center and regularly plans for emergency situations and develops response protocols.

Elements of the Department's cybersecurity program include ongoing monitoring, regular staff training and a robust defense-in-depth strategy, as well as other cybersecurity and operational safeguards such as performance of periodic security risk assessments and gap analyses to identify security strengths and vulnerabilities; practices for the backup and recovery of data; security awareness training, and response plans.

The Department also collaborates with federal and state partners and other public and private third parties to assess vulnerabilities, share information and actively detect and manage risks. However, there can be no assurance that any existing or additional safety and security measures will prove adequate in the event that cyberattacks or military conflicts or terrorist activities (including cyber terrorism) are directed against the Power System.

Attacks, especially zero-day exploits directed at critical electric sector operations could damage generation, transmission or distribution assets, cause operational malfunctions and outages, and result in costly recovery and remediation efforts. Further, cyberattacks are becoming more sophisticated and certain cyber incidents, such as surveillance, may remain undetected for an extended period. United States government agencies have in the past issued warnings indicating that critical infrastructure sectors such as the electric grid may be specific targets of cybersecurity threats. The costs of security measures or of remedying physical and/or cybersecurity breaches could be material.

Global Health Emergencies; COVID-19 Pandemic

A pandemic, epidemic or outbreak of an infectious disease can have significant adverse health and financial impacts on global and local economies. For example, beginning in 2020, the COVID-19 pandemic negatively affected economic activity throughout the world, including the United States and the State of California. The initial impacts of stay-at home orders globally were unprecedented, with commerce, travel, asset values and financial markets experiencing disruptions worldwide. The COVID-19 pandemic impacted the Department in certain respects; however, there was not a material adverse impact to the Power System's operations or its ability to meet its financial obligations as a result of the COVID-19 pandemic. Certain employees of electric and water utility systems, like the Department, are considered essential workers and were exempt from the "stay at home" and "safer at home" orders issued by the State, the County and the City, and therefore, the Department continued to fully provide power and water services to its customers throughout the pandemic. In response to the COVID-19 outbreak, the Department implemented a number of temporary measures intended to mitigate operational and financial impacts to the Department, and to assist the Department's customers. In light of the measures taken by the Department to mitigate the economic impact of COVID-19 on its customers, including extended payment options and deferrals of disconnections of water and power services for non-payment, the Department has experienced and may continue to experience an increase in delinquent accounts and increase of uncollectible accounts. See "ELECTRIC RATES – Billings and Collections – *COVID-19 Effects*."

The declarations of the COVID-19 pandemic as a public health emergency have been lifted. However, future pandemics and other widespread public health emergencies can and do arise from time to time. No assurance can be given that the operations or finances of the Power System will not be negatively affected in the event that the pandemic and its consequences again become more severe or another national or localized outbreak of highly contagious or epidemic disease occurs in the future.

Changing Laws and Requirements

On both the state and federal levels, legislation is introduced frequently that would have the effect of further regulating environmental impacts relating to energy, including the generation of energy using conventional and unconventional technologies. Issues raised in recent legislative proposals have included implementation of energy efficiency and renewable energy standards, addressing transmission planning, siting and cost allocation to support the construction of renewable energy facilities, cyber-security legislation that would allow FERC to issue interim measures to protect critical electric infrastructure, and renewable energy incentives that could provide grants and credits to municipal utilities to invest in renewable energy infrastructure. Congress has also considered other bills relating to energy supplies and development.

The Department is unable to predict at this time whether any of these or other legislative proposals will be enacted into law and, if so, the impact they may have on the operations and finances of the Power System or on the electric utility industry in general.

In addition to state and federal legislation, citizen initiatives in the State can lead and have led to substantial restrictions upon governmental agencies, both in terms of raising revenue and management of governmental entities generally. Articles XIII C and XIII D of the State's constitution provided limits on the ability of governmental agencies to increase certain fees and charges. Such articles were adopted pursuant to measures qualified for the ballot pursuant to the State's constitutional initiative process.

In addition, from time to time other initiative measures could be adopted by State voters, which may place limitations on the ability of the Department to increase revenues. Such initiatives may purport to be retroactive.

See also "ELECTRIC RATES – Rate Setting – *Proposition 26*."

Other General Factors

The electric utility industry in general has been, or in the future may be, affected by a number of factors which could impact the financial condition and competitiveness of many electric utilities, including the Department, and the level of utilization of generation and transmission facilities. Such factors (a number of which are further discussed elsewhere in this Official Statement), include, among others:

- Effects of compliance with rapidly changing environmental, safety, licensing, regulatory and legislative requirements;
- Changes resulting from conservation and demand side management programs on the timing and use of energy;
- Effects on the integration and reliability of the power supply from the increased usage of renewables;
- Changes resulting from a national energy policy;
- Effects of competition from other electric utilities (including increased competition resulting from mergers, acquisitions and strategic alliances of competing electric and natural gas utilities

and from competitive transmitting of less expensive electricity from much greater distances over an interconnected system) and new methods of, and new facilities for, producing low-cost electricity;

- The repeal of certain federal statutes that would have the effect of increasing the competitiveness of many investor-owned utilities;

- Increased competition from independent power producers and marketers, brokers and federal power marketing agencies;

- "Self-generation" or "distributed generation" (such as microturbines, fuel cells, and solar installations) by industrial and commercial customers and others;

- Issues relating to the ability to issue tax-exempt obligations, including restrictions on the ability to sell to nongovernmental entities electricity from generation projects and transmission line service from transmission projects financed with outstanding tax-exempt obligations;

- Effects of inflation on the operating and maintenance costs of an electric utility and its facilities;

- Changes from projected future load requirements;

- Increases in costs and uncertain availability of capital;

- Shifts in the availability and relative costs of different fuels (including the cost of natural gas and coal);

- Financial difficulties, including bankruptcy, of fuel suppliers and/or renewable energy suppliers;

- Changes in the electric market structure for neighboring electric grids such as the EIM operated by the Cal ISO;

- Sudden and dramatic increases in the price of energy purchased on the open market that may occur in times of high peak demand in an area of the country experiencing such high peak demand, such as has occurred in the State;

- Inadequate risk management procedures and practices with respect to, among other things, the purchase and sale of energy and transmission capacity;

- Other legislative changes, voter initiatives, referenda and statewide propositions;

- Effects of changes in the economy, population and demand of customers in the Department's service area;

- Effects of possible manipulation of the electric markets;

- Acts of terrorism or cyberterrorism;

- Impacts of climate change;

- The outbreak of another infectious disease such as the COVID-19 pandemic impacting the global, national or local economy or a utility's service area;

- Natural disasters or other physical calamities, including but not limited to, earthquakes, floods and wildfires, and potential liabilities of electric utilities in connection therewith;

- Adverse impacts to the market for insurance relating to recent wildfires and other calamities, leading to higher costs or prohibitively expensive coverage, or limited or unavailability of coverage for certain types of risk; and

- Legislation or court actions allowing City residents and/or businesses to purchase power from sources outside the Department.

Any of these factors (as well as other factors) could have an adverse effect on the financial condition of any given electric utility, including the Department.

Seismic Activity

The City and the Owens River and Mono Basin areas are located in regions of seismic activity. The principal earthquake fault in the Los Angeles area is the San Andreas Fault, which extends an estimated 700 miles from north of the San Francisco area to the Salton Sea. At its nearest point to the City, the San Andreas Fault is about 35 miles north of the Los Angeles Civic Center.

In March 2015, the Uniform California Earthquake Rupture Forecast (the "2015 Earthquake Forecast") was issued by the Working Group on California Earthquake Probabilities. Organizations sponsoring the Working Group on California Earthquake Probabilities include the U.S. Geological Survey, the California Geological Survey, the Southern California Earthquake Center and the California Earthquake Authority. According to the 2015 Earthquake Forecast, the probability of a magnitude 6.7 or larger earthquake over the next 30 years (from 2014) striking the greater Los Angeles area is 60%. From the Uniform California Earthquake Rupture Forecast published in April 2008 (the "2008 Earthquake Forecast"), the estimated rate of earthquakes around magnitude 6.7 or larger decreased by about 30%. However, the estimate for the likelihood that the State will experience a magnitude 8.0 or larger earthquake in the next 30 years (from 2014) increased from about 4.7% in the 2008 Earthquake Forecast to about 7.0% in the 2015 Earthquake Forecast. The 2015 Earthquake Forecast considered more than 250,000 different fault-based earthquakes, including multi-fault ruptures, whereas the 2008 Earthquake Forecast considered approximately 10,000 different fault-based earthquakes.

While it is impossible to accurately predict the cost or effect of a major earthquake on the Power System or to predict the effect of such an earthquake on the Department's ability to provide continued uninterrupted service to all parts of the Department's service area, there have been various studies conducted to assist the Department in assessing seismic risks. Based on these studies, the Department completed numerous projects designed to mitigate seismic risks and seismically strengthen Power System infrastructure and facilities. Projects include landslide repairs and bank replacements, the placement of spare transformers and the installation of generating peaking units at the Valley Generating Station and Haynes Generating Station to provide peaking capacity and the ability for generating units to go from a shutdown condition to an operating condition and start delivering power without assistance from the power grid. No studies have been conducted or commissioned by the Department outside of the State. See "THE DEPARTMENTOF WATER AND POWER OF THE CITY OF LOS ANGELES – Insurance."

LITIGATION

General

A number of claims and suits are pending against the Department or that directly affect the Department with respect to the Power System for alleged damages to persons and property and for other alleged liabilities arising out of its operations. Certain of these suits are described below. In the opinion of the Department, any ultimate liability which may arise from any of the pending claims and suits is not expected to materially impact the Power System's financial position, results of operations, or cash flows.

Wildfire Litigation

In recent years, there has been an increase in the number and the severity of wildfires in the State. Due to this increase of fire activity, there has been an increase in litigation filed against power utilities that own and operate generating stations, distribution lines, and transmission lines throughout the State. The Department is a named party in cases relating to the Creek fire, which ignited on December 5, 2017, and the Getty fire, which ignited on October 28, 2019. The Department denies liability for the ignition of the Creek fire. The unique set of facts regarding the ignition of the Getty fire likely creates Department liability; however, various defense theories and third party claims are being explored.

Creek Fire. Regarding the Creek fire, the Department has a number of cases pending in the Los Angeles Superior Court. The state court cases are brought by attorneys representing individual plaintiffs for alleged property damage and business losses. The cases have all been consolidated for litigation with a single judge. Edison is also a party in the state court cases, and is a focus of the fire ignition. Edison was named as a co-defendant by the individual plaintiff and insurance subrogation plaintiffs. Edison has filed an indemnity cross-complaint against the Department. All equitable allegations/comparative fault allegations would be part of the state court trial. On September 15, 2023, as a result of the court's ruling on a joint motion by the Department and Edison to dismiss certain plaintiff cases, a significant number of individual plaintiff cases were dismissed, leaving approximately 300 individual plaintiff cases. The dismissals significantly reduce the Department's financial exposure for the wildfire.

The Department has filed a motion for summary judgment, which was heard on September 25, 2024. Should the motion be denied, the judge has scheduled a trial in this matter for October 7, 2024, regarding only the issue of liability under the theory of inverse condemnation. At that trial the court will determine if inverse condemnation applies, and if so, whether the Department or Edison is responsible for causing the fire. A later date will be set at which a jury will decide the amount of damages.

If liability is found against the Department in connection with the Creek fire, an accurate exposure amount cannot now be estimated. However, the cumulative alleged damages in the pending state court cases, which now include only individual plaintiff cases and a reduced number of plaintiffs, is within the Department's insurance coverage for this matter. The Department has insurance coverage for this matter in the amount of $185 million with a $3 million self-insured retention.

Getty Fire. The Power System matters associated with the Getty fire currently involve multiple cases all alleging inverse condemnation and tort causes of action. The state court actions were filed on behalf of individual plaintiffs and insurance subrogation parties. The cases are pending in the Los Angeles Superior Court Complex Division with all cases ordered consolidated/related before a single judge.

Cross-complaints have been filed by the Department naming the adjacent property owner C&C Mountaingate, Inc., and Department tree vegetation contractor Utility Tree Service, LLC and its subcontractor, Tree Service Kings, Inc.

The total financial exposure of the Getty Wildfire is likely set at approximately $81.3 million, which represents the estimated total for anticipated settlement agreements with all plaintiffs. The Department is responsible for $3 million of this amount; the rest is covered by insurance. On or about October 16, 2023, the Department settled with the insurance subrogation plaintiffs for $36,355,272, which is finalized. The Department is in the process of finalizing a settlement with the individual plaintiff group.

The Department has insurance coverage in the amount of $177.5 million with a $3 million self-insured retention for this matter. For details regarding the extent of the Department's current insurance, see "THE DEPARTMENT OF WATER AND POWER OF THE CITY OF LOS ANGELES – Insurance." As discussed under "FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY – California Climate Change Policy Developments – *Legislation and Court Action Relating to Wildfires*," legislation addressing the State's inverse condemnation and "strict liability" issues for utilities in the context of wildfires in particular could have a significant effect on the electric utility industry, including the Department.

APPENDIX D

DEBT SERVICE REQUIREMENTS FOR 2022 SERIES A AND B BONDS, 2023 SERIES A AND B BONDS AND 2024 SERIES A AND B BONDS (Accrual Basis)

(in thousands (000))

	2022 Series A and B Bonds				2023 Series A and B Bonds				2024 Series A and B Bonds				Total
Year Ending July 1,	Principal	Interest	Less: Capitalized Interest (1)	Total (2)	Principal	Interest	Less: Capitalized Interest (1)	Total (2)	Principal	Interest	Less: Capitalized Interest (1)	Total (2)	2022 Series A and B, 2023 Series A and B and 2024 Series A and B Bonds (2)
2025	–	$ 39,348	$(39,348)	–	–	$ 42,425	$(42,425)	–	–	$ 5,512	$(5,512)	–	–
2026	$ 24,400	39,348	–	$ 63,748	$ 25,215	42,425	–	$ 67,640	$ 5,290	8,781	–	$ 14,071	$ 145,458
2027	25,585	38,160	–	63,745	26,475	41,164	–	67,639	5,555	8,518	–	14,073	145,457
2028	26,835	36,910	–	63,745	27,795	39,840	–	67,635	5,830	8,242	–	14,072	145,453
2029	28,150	35,596	–	63,746	29,185	38,451	–	67,636	6,120	7,952	–	14,072	145,455
2030	29,535	34,216	–	63,751	30,650	36,992	–	67,642	6,425	7,647	–	14,072	145,466
2031	30,980	32,766	–	63,746	32,180	35,458	–	67,638	6,740	7,327	–	14,067	145,451
2032	32,505	31,241	–	63,746	33,790	33,849	–	67,639	7,085	6,991	–	14,076	145,462
2033	34,105	29,638	–	63,743	35,480	32,160	–	67,640	7,435	6,638	–	14,073	145,456
2034	35,795	27,952	–	63,747	37,250	30,385	–	67,635	7,810	6,266	–	14,076	145,458
2035	37,570	26,178	–	63,748	39,115	28,519	–	67,634	8,200	5,876	–	14,076	145,458
2036	39,435	24,312	–	63,747	41,080	26,556	–	67,636	8,610	5,463	–	14,073	145,455
2037	41,035	22,712	–	63,747	43,145	24,491	–	67,636	9,045	5,030	–	14,075	145,458
2038	43,080	20,667	–	63,747	45,320	22,319	–	67,639	9,500	4,574	–	14,074	145,460
2039	45,245	18,504	–	63,749	47,600	20,035	–	67,635	9,980	4,096	–	14,076	145,461
2040	47,515	16,233	–	63,748	49,995	17,631	–	67,626	10,485	3,594	–	14,079	145,453
2041	49,900	13,848	–	63,748	52,510	15,107	–	67,617	11,010	3,066	–	14,076	145,440
2042	52,405	11,342	–	63,747	55,155	12,455	–	67,610	11,565	2,511	–	14,076	145,433
2043	55,035	8,712	–	63,747	57,930	9,669	–	67,599	12,150	1,929	–	14,079	145,425
2044	57,795	5,949	–	63,744	60,980	6,610	–	67,590	12,760	1,317	–	14,077	145,411
2045	60,700	3,047	–	63,747	64,195	3,390	–	67,585	13,405	675		14,080	145,412
Total (2)	$797,605	$516,680	$(39,348)	$1,274,938	$835,045	$559,928	$(42,425)	$1,352,549	$175,000	$112,006	$(5,512)	$281,494	$2,908,980

(1) Capitalized interest through 7/1/2025.
(2) Row and column totals may not add due to rounding.

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PROPOSED FORM OF OPINION OF BOND COUNSEL

Upon the delivery of the 2024 Series A and B Bonds, Orrick, Herrington & Sutcliffe LLP, New York, New York, Bond Counsel to the Agency, proposes to render its final approving opinion with respect to such Bonds in substantially the following form:

November __, 2024

Board of Directors
Intermountain Power Agency
South Jordan, Utah 84095

Intermountain Power Agency
Power Supply Revenue Bonds, 2024 Series A (Tax-Exempt)
and 2024 Series B (Federally Taxable)

Gentlemen:

We have acted as bond counsel to Intermountain Power Agency (the "Agency"), a political subdivision of the State of Utah, in connection with the issuance of $161,215,000 aggregate principal amount of Power Supply Revenue Bonds, 2024 Series A (Tax-Exempt) (the "2024 Series A Bonds") and $13,785,000 aggregate principal amount of Power Supply Revenue Bonds, 2024 Series B (Federally Taxable) (the "2024 Series B Bonds" and, together with the 2024 Series A Bonds, the "2024 Series A and B Bonds"), issued pursuant to the provisions of the Utah Interlocal Cooperation Act (constituting Title 11, Chapter 13 of the Utah Code Annotated, 1953, as amended (the "Act")), and under and pursuant to a resolution of the Agency adopted on September 28, 1978 entitled "Power Supply Revenue Bond Resolution," as heretofore supplemented, amended and restated, including as supplemented by a resolution supplemental thereto adopted by the Agency on October 2, 2024 entitled "Sixty-Sixth Supplemental Power Supply Revenue Bond Resolution" (such Power Supply Revenue Bond Resolution, as so supplemented, amended and restated, being herein called the "Resolution"). The 2024 Series A and B Bonds constitute "Bonds" within the meaning of the Resolution. Capitalized terms not otherwise defined herein shall have the meanings ascribed thereto in the Resolution.

The Resolution provides that the 2024 Series A and B Bonds are being issued for the stated purposes of financing a portion of the Cost of Acquisition and Construction of the Gas Repowering of the Project, funding a deposit to a debt service reserve account, funding capitalized interest on the 2024 Series A and B Bonds through July 1, 2025 and paying costs of issuance of the 2024 Series A and B Bonds. The Agency reserves the right to issue additional Bonds on the terms and conditions and for the purposes stated in the Resolution. Under the provisions of the Resolution, all Outstanding Bonds shall rank equally as to security and payment from the Trust Estate.

The Agency has entered into thirty-five separate Power Sales Contracts with the following purchasers (the "Power Purchasers") of capability of the Project: twenty-three municipally-owned electric systems in the State of Utah (the "Utah Purchasers"), six rural electric cooperatives rendering electric service in the State of Utah (the "Cooperative Purchasers") and six municipalities in the State of California (the "California Purchasers"). Said Power Sales Contracts have heretofore been amended, including (a) the amendments thereto provided for by the thirty-five separate Amendatory Power Sales Contracts entered into between the Agency and each of the thirty-five Power Purchasers, and (b) the amendments thereto provided for by the thirty-five separate Second Amendatory Power Sales Contracts entered into between the Agency and each of the thirty-five Power Purchasers (the "Second Amendatory Power Sales Contracts"), the appendices to such Power Sales Contracts have been updated in accordance with the terms of such Power Sales Contracts and such Power Sales Contracts have been revised pursuant to Section 44.1 of such Power Sales Contracts by the Alternative Repowering Revisions (as defined in such Power Sales Contracts) approved by Resolution No. CC-2018-010 of the Intermountain Power Project Coordinating Committee, Resolution No. RCCC-2018-004 of the Intermountain Power Project Renewal Contract Coordinating Committee and Resolution No. IPA-2018-019 of the Agency's Board of Directors on September 24, 2018 (said Power Sales Contracts, as so amended, updated and revised, are herein called the "Power Sales Contracts").

The Agency also has entered into thirty separate Renewal Power Sales Contracts with the following purchasers (the "Renewal Power Purchasers") of capability of the Project from and after June 16, 2027: twenty-one municipally-owned electric systems in the State of Utah (the "Utah Renewal Purchasers"), the Cooperative Purchasers and three of the six California Purchasers (the "California Renewal Purchasers"), as the appendices to such Renewal Power Sales Contracts heretofore have been updated in accordance with the terms of such Renewal Power Sales Contracts (said Renewal Power Sales Contracts, as so updated, are herein called the "Renewal Power Sales Contracts").

As bond counsel, we have reviewed certified copies of the Resolution, the Power Sales Contracts and the Renewal Power Sales Contracts; the Tax Certificate executed and delivered by the Agency on the date hereof in connection with the issuance of the 2024 Series A Bonds (the "Tax Certificate"); opinions of counsel to the Agency, the Power Purchasers and the Renewal Power Purchasers; certificates of the Agency, the Trustee and others; and such other documents, opinions and matters to the extent we deemed necessary to render the opinions set forth herein.

The opinions expressed herein are based upon an analysis of existing laws, regulations, rulings and court decisions and cover certain matters not directly addressed by such authorities. Such opinions may be affected by actions taken or omitted or events occurring after original delivery of the 2024 Series A and B 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 2024 Series A and B 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 2024 Series A and B Bonds has concluded with their issuance, and we disclaim any obligation to update this letter. We have assumed (a) the genuineness of all documents and signatures provided to us, (b) the due and legal execution and delivery of all documents provided to us by any parties other than the Agency (except that we did not personally witness the execution and delivery on behalf of the Agency of any of the Power Sales Contracts or any amendment thereto or any of the Renewal Power Sales Contracts so, for purposes of the opinions expressed in paragraphs 4 and 5 below, we have relied solely upon a certificate of the Agency to the effect, among other things, that the Power Sales Contracts and the amendments thereto and the Renewal Power Sales Contracts have been duly executed and delivered on behalf of the Agency) and (c) the validity of all documents provided to us against any parties other than the Agency and, with respect to the Power Sales Contracts, the Power Purchasers and, with respect to the Renewal Power Sales Contracts, the Renewal Power Purchasers. 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 of this letter (except that we have not relied on any such legal conclusions that are to the same effect as the opinions set forth herein). Furthermore, we have assumed compliance with all covenants and agreements contained in the Resolution, the Power Sales Contracts, the Renewal Power Sales Contracts and the Tax Certificate, 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 2024 Series 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 2024

Series A and B Bonds, the Resolution, the Power Sales Contracts, the Renewal Power Sales Contracts and the Tax Certificate 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 political subdivisions of the State of Utah. We express no opinion with respect to any indemnification, contribution, liquidated damages, penalty (including any remedy deemed to constitute a penalty), right of set-off, arbitration, choice of law, choice of forum, choice of venue, non-exclusivity of remedies, waiver or severability provisions contained in the foregoing documents. Our services did not include financial or other non-legal advice. Finally, we undertake no responsibility for the accuracy, completeness or fairness of the Official Statement of the Agency, dated October 25, 2024, relating to the 2024 Series A and B Bonds or other offering material relating to the 2024 Series A and B Bonds and express no opinion or view with respect thereto.

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

1. The Agency is duly created and validly existing under the provisions of the Act and has the legal right and lawful authority under the Act to acquire and construct the Project and provide for the operation and maintenance thereof.

2. The Agency has the right and power under the Act to adopt the Resolution, and the Resolution has been duly and lawfully adopted by the Agency, is in full force and effect in accordance with its terms and is valid and binding upon the Agency and enforceable in accordance with its terms, and no other authorization for the Resolution is required. The Resolution creates the valid pledges and assignments it purports to create of the Trust Estate and the Initial Subaccount in the Debt Service Reserve Account in the Debt Service Fund established pursuant to the Resolution, subject only to the provisions of the Resolution permitting the application thereof for the purposes and on the terms and conditions set forth in the Resolution.

3. The Agency is duly authorized and entitled to issue the 2024 Series A and B Bonds, and the 2024 Series A and B Bonds have been duly and validly authorized and issued by the Agency in accordance with the Constitution and laws of the State of Utah, including the Act, and the Resolution. The 2024 Series A and B Bonds constitute the valid and binding obligations of the Agency as provided in the Resolution, are enforceable in accordance with their terms and the terms of the Resolution and are entitled to the benefits of the Act and the Resolution. Neither the State of Utah nor any political subdivision thereof (other than the Agency) nor any member of the Agency nor any Power Purchaser nor the Project Manager or the Operating Agent under the Construction Management and Operating Agreement shall be obligated to pay the principal or redemption price of, or interest on, the 2024 Series A and B Bonds and neither the faith and credit nor the taxing power of the State of Utah or any political subdivision thereof or of any city or town which is either a member of the Agency or a Power Purchaser or both is pledged to the payment of the principal or redemption price of, or interest on, the 2024 Series A and B Bonds. No Holder of any 2024 Series A and B Bond or receiver or trustee in connection with the payment of the 2024 Series A and B Bonds shall have any right to compel the State of Utah, any political subdivision thereof or any city or town which is either a member of the Agency or a Power Purchaser or both to exercise its appropriation or taxing powers.

4. The Agency has the right and power to enter into and carry out its obligations under the Power Sales Contracts and has duly authorized, executed and delivered the Power Sales Contracts which constitute valid and binding agreements of the Agency in accordance with their terms.

5. The Agency has the right and power to enter into and carry out its obligations under the Renewal Power Sales Contracts and has duly authorized, executed and delivered the Renewal Power Sales Contracts which constitute valid and binding agreements of the Agency in accordance with their terms.

6. Under the Constitution and laws of the State of Utah, each Power Sales Contract with a Utah Purchaser constitutes a valid and binding agreement of the Utah Purchaser party thereto in accordance with its terms. In rendering the foregoing opinion, we have made no investigation of, and do not express any opinion with respect to, the following as they may relate to the valid and binding nature of such Power Sales Contracts: (i) the legal existence or formation of any Utah Purchaser or the incumbency of any official or officer thereof, (ii) the charter, by laws or other governing instrument of any Utah Purchaser, (iii) any local or special acts or any ordinance, resolution or other proceedings of any Utah Purchaser, including, without limitation, any proceedings relating to the negotiation or authorization of any such Power Sales Contract or amendment thereto or the execution, delivery or performance thereof, (iv) any bond resolution, indenture, contract, debt instrument, agreement or other instrument (other than such Power Sales Contracts and amendments thereto) or any governmental order, regulation or rule of or applicable to any Utah Purchaser, (v) any judicial order, judgment or decree in a proceeding to which any Utah Purchaser is a party (other than the proceedings and order in the case of *Murray City v. Brown* (1980) which involved the Power Sales Contract with the Utah Purchaser of Murray City, Utah) or (vi) any approval, consent, filing, registration or authorization by or with any regulatory authority or other governmental or public agency, authority or person which may be or has been required for the authorization, execution, delivery or performance by any Utah Purchaser of its Power Sales Contract or any amendment thereto. The Agency received in March 1983 opinions with respect to, among other things, the validity and enforceability of the Power Sales Contracts, as theretofore amended, with the Utah Purchasers rendered by legal counsel to the respective Utah Purchasers and, in addition, received from such counsel (a) confirmations of such opinions dated the date hereof and (b) opinions dated December 8, 2015, other than the opinion of counsel to the Utah Purchaser of Heber Light & Power Company, which was dated March 11, 2016, to the effect, among other things, that the Second Amendatory Power Sales Contract to which each such Utah Purchaser is a party has been duly authorized, executed and delivered by such Utah Purchaser.

7. Under the Constitution and laws of the State of Utah (or Nevada, in the case of the Cooperative Purchaser organized under the laws of said State, or Wyoming, in the case of the Cooperative Purchaser organized under the laws of said State), each Power Sales Contract with a Cooperative Purchaser constitutes a valid and binding agreement of the Cooperative Purchaser party thereto in accordance with its terms. In rendering the foregoing opinion, we have made no investigation of, and do not express any opinion with respect to, the following as they may relate to the valid and binding nature of such Power Sales Contracts: (i) the legal existence or formation of any Cooperative Purchaser or the incumbency of any official or officer thereof, (ii) the articles of incorporation, charter, by laws or other governing instrument of any Cooperative Purchaser, (iii) any local or special acts or any resolution or other proceedings of any Cooperative Purchaser, including, without limitation, any proceedings relating to the negotiation or authorization of any such Power Sales Contract or amendment thereto or the execution, delivery or performance thereof, (iv) any mortgage, indenture, contract, debt instrument, agreement or other instrument (other than such Power Sales Contracts and amendments thereto) or any governmental order, regulation or rule of or applicable to any Cooperative Purchaser, (v) any judicial order, judgment or decree in a proceeding to which any Cooperative Purchaser is a party or (vi) any approval, consent, filing, registration or authorization by or with any regulatory authority or other governmental or public agency, authority or person which may be or has been required for the authorization, execution, delivery or performance by any Cooperative Purchaser of its Power Sales Contract or any amendment thereto. The Agency received in March 1983

opinions with respect to, among other things, the validity and enforceability of the Power Sales Contracts, as theretofore amended, with the Cooperative Purchasers rendered by legal counsel to the respective Cooperative Purchasers and, in addition, received from such counsel (a) opinions dated December 8, 2015, to the effect, among other things, that the Second Amendatory Power Sales Contract to which each such Cooperative Purchaser is a party has been duly authorized, executed and delivered by such Cooperative Purchaser and (b) confirmations of such opinions dated the date hereof, other than confirmations of such opinions with respect to a Cooperative Purchaser with a Generation Cost Share and a Generation Entitlement Share (as such terms are defined in the Power Sales Contracts) of 0.20 percent.

8. Under the Constitution and laws of the State of California and the respective charters of the California Purchasers, each Power Sales Contract with a California Purchaser constitutes a valid and binding agreement of the California Purchaser party thereto in accordance with its terms. In rendering the foregoing opinion, we have made no investigation of, and do not express any opinion with respect to, the following as they may relate to the valid and binding nature of such Power Sales Contracts: (i) the legal existence or formation of any California Purchaser or the incumbency of any official or officer thereof, (ii) any local or special acts or any ordinance, resolution or other proceedings of any California Purchaser, including, without limitation, any proceedings relating to the negotiation or authorization of any such Power Sales Contract or amendment thereto or the execution, delivery or performance thereof (except that we have examined the respective ordinances and resolutions pursuant to which the Power Sales Contracts of the California Purchasers were authorized by the respective California Purchasers), (iii) any bond resolution, indenture, contract, debt instrument, agreement or other instrument (other than such Power Sales Contracts and amendments thereto) or any governmental order, regulation or rule of or applicable to any California Purchaser, (iv) any judicial order, judgment or decree in a proceeding to which any California Purchaser is a party or (v) any approval, consent, filing, registration or authorization by or with any regulatory authority or other governmental or public agency, authority or person which may be or has been required for the authorization, execution, delivery or performance by any California Purchaser of its Power Sales Contract or any amendment thereto. The Agency received in March 1983 opinions with respect to, among other things, the validity and enforceability of the Power Sales Contracts, as theretofore amended, with the California Purchasers rendered by legal counsel to the respective California Purchasers and, in addition, received from such counsel (a) confirmations of such opinions dated the date hereof and (b) opinions dated March 11, 2016, other than the opinions of counsel to the California Purchaser of the Department of Water and Power of the City of Los Angeles, which were dated February 26, 2016, to the effect, among other things, that the Second Amendatory Power Sales Contract to which each such California Purchaser is a party has been duly authorized, executed and delivered by such California Purchaser.

9. Under the Constitution and laws of the State of Utah, each Renewal Power Sales Contract with a Utah Renewal Purchaser constitutes a valid and binding agreement of the Utah Renewal Purchaser party thereto in accordance with its terms. In rendering the foregoing opinion, we have made no investigation of, and do not express any opinion with respect to, the following as they may relate to the valid and binding nature of such Renewal Power Sales Contracts: (i) the legal existence or formation of any Utah Renewal Purchaser or the incumbency of any official or officer thereof, (ii) the charter, by laws or other governing instrument of any Utah Renewal Purchaser, (iii) any local or special acts or any ordinance, resolution or other proceedings of any Utah Renewal Purchaser, including, without limitation, any proceedings relating to the negotiation or authorization of any such Renewal Power Sales Contract or the execution, delivery or performance thereof, (iv) any bond resolution, indenture, contract, debt instrument, agreement or other instrument (other than such Renewal Power Sales Contracts) or any governmental order, regulation or rule of or applicable to any Utah Renewal Purchaser, (v) any judicial order, judgment or decree in a proceeding to which any Utah Renewal Purchaser is a

party or (vi) any approval, consent, filing, registration or authorization by or with any regulatory authority or other governmental or public agency, authority or person which may be or has been required for the authorization, execution, delivery or performance by any Utah Renewal Purchaser of its Renewal Power Sales Contract. The Agency received in January 2017 opinions with respect to, among other things, the validity and enforceability of the Renewal Power Sales Contracts with the Utah Renewal Purchasers rendered by legal counsel to the respective Utah Renewal Purchasers and, in addition, received from such counsel confirmations of such opinions dated the date hereof.

10. Under the Constitution and laws of the State of Utah (or Nevada, in the case of the Cooperative Purchaser organized under the laws of said State, or Wyoming, in the case of the Cooperative Purchaser organized under the laws of said State), each Renewal Power Sales Contract with a Cooperative Purchaser constitutes a valid and binding agreement of the Cooperative Purchaser party thereto in accordance with its terms. In rendering the foregoing opinion, we have made no investigation of, and do not express any opinion with respect to, the following as they may relate to the valid and binding nature of such Renewal Power Sales Contracts: (i) the legal existence or formation of any Cooperative Purchaser or the incumbency of any official or officer thereof, (ii) the articles of incorporation, charter, by laws or other governing instrument of any Cooperative Purchaser, (iii) any local or special acts or any resolution or other proceedings of any Cooperative Purchaser, including, without limitation, any proceedings relating to the negotiation or authorization of any such Renewal Power Sales Contract or the execution, delivery or performance thereof, (iv) any mortgage, indenture, contract, debt instrument, agreement or other instrument (other than such Renewal Power Sales Contracts) or any governmental order, regulation or rule of or applicable to any Cooperative Purchaser, (v) any judicial order, judgment or decree in a proceeding to which any Cooperative Purchaser is a party or (vi) any approval, consent, filing, registration or authorization by or with any regulatory authority or other governmental or public agency, authority or person which may be or has been required for the authorization, execution, delivery or performance by any Cooperative Purchaser of its Renewal Power Sales Contract. The Agency received in January 2017 opinions with respect to, among other things, the validity and enforceability of the Renewal Power Sales Contracts with the Cooperative Purchasers rendered by legal counsel to the respective Cooperative Purchasers and, in addition, received from such counsel confirmations of such opinions dated the date hereof, other than a confirmation of such opinion with respect to a Cooperative Purchaser with a Generation Cost Share and a Generation Entitlement Share (as such terms are defined in the Renewal Power Sales Contracts) of 0.202 percent.

11. Under the Constitution and laws of the State of California and the respective charters of the California Renewal Purchasers, each Renewal Power Sales Contract with a California Renewal Purchaser constitutes a valid and binding agreement of the California Renewal Purchaser party thereto in accordance with its terms. In rendering the foregoing opinion, we have made no investigation of, and do not express any opinion with respect to, the following as they may relate to the valid and binding nature of such Renewal Power Sales Contracts: (i) the legal existence or formation of any California Renewal Purchaser or the incumbency of any official or officer thereof, (ii) any local or special acts or any ordinance, resolution or other proceedings of any California Renewal Purchaser, including, without limitation, any proceedings relating to the negotiation or authorization of any such Renewal Power Sales Contract or the execution, delivery or performance thereof, (iii) any bond resolution, indenture, contract, debt instrument, agreement or other instrument (other than such Renewal Power Sales Contracts) or any governmental order, regulation or rule of or applicable to any California Renewal Purchaser, (iv) any judicial order, judgment or decree in a proceeding to which any California Renewal Purchaser is a party or (v) any approval, consent, filing, registration or authorization by or with any regulatory authority or other governmental or public agency, authority or person which may be or has been required for the authorization, execution,

delivery or performance by any California Renewal Purchaser of its Renewal Power Sales Contract. The Agency received in January 2017 opinions with respect to, among other things, the validity and enforceability of the Renewal Power Sales Contracts with the California Renewal Purchasers rendered by legal counsel to the respective California Renewal Purchasers and, in addition, received from such counsel confirmations of such opinions dated the date hereof.

12. Interest on the 2024 Series A Bonds is excluded from gross income for federal income tax purposes under Section 103 of the Internal Revenue Code of 1986. Interest on the 2024 Series A Bonds is not a specific preference item for purposes of the federal individual alternative minimum tax. We observe that interest on the 2024 Series A Bonds included in adjusted financial statement income of certain corporations is not excluded from the federal corporate alternative minimum tax.

13. Interest on the 2024 Series B Bonds is not excluded from gross income for federal income tax purposes under Section 103 of the Internal Revenue Code of 1986.

14. Interest on the 2024 Series A and B Bonds is exempt from individual income taxes imposed by the State of Utah.

Except as stated in paragraphs 12, 13 and 14 hereof, 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 2024 Series A and B Bonds.

Faithfully yours,

ORRICK, HERRINGTON & SUTCLIFFE LLP

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