ANNUAL REPORT
(Pursuant to S.E.C. Rule 15c2-12)
December 30, 2025

Relating to:
$74,765,000 Southern California Public Power Authority
Linden Wind Energy Project, Refunding Revenue Bonds, 2024 Series A
(Variable Rate Demand Bonds) (Green Bonds)

INTRODUCTION

This Annual Report is filed pursuant to the Continuing Disclosure Resolution (Resolution No. 2023-131), adopted by the Southern California Public Power Authority (the "Authority" or "SCPPA") on November 16, 2023 (the "Disclosure Resolution"), in accordance with Securities and Exchange Commission Rule 15c2-12 (the "Rule"). This Annual Report relates to the above-captioned bonds (the "Bonds"). The Bonds are described in the Authority's Official Statement dated January 16, 2024 (the "Official Statement"). Except as otherwise provided herein, terms used herein that are not defined herein have the meanings ascribed to such terms in the Official Statement.

The information in this Annual Report is provided in order to comply with the Authority's contractual commitment established by the Disclosure Resolution to provide certain of the information specified therein. Certain information in this Annual Report is not required to be provided by the Disclosure Resolution. By providing such information, the Authority does not undertake or agree to provide such information in any future year. The Authority, the Department of Water and Power of the City of Los Angeles (the "Department") and the City of Glendale, California ("Glendale," and together with the Department, the "Participants") make no representation that this Annual Report contains all information material to a decision to purchase or sell any of the Bonds.

The information set forth herein has been furnished by the Authority and the Participants and includes information obtained from other sources, which are believed to be reliable. Any statements herein involving matters of opinion or estimates, whether or not so expressly stated, are set forth as such and not as representations of fact, and no representation is made that such opinion or estimates will be realized. The information and expressions of opinion contained in this Annual Report are provided as of the respective dates specified herein and are subject to change without notice, and the filing of this Annual Report shall not, under any circumstances, create any implication that there has been no change in the affairs of the Authority or any Participant or in the other matters described herein since the date as of which such information is provided.

THE LINDEN WIND ENERGY PROJECT

General Description

The Bonds were issued in part to refinance costs of acquisition of the Linden Wind Energy Project, an approximately 50 MW nameplate capacity wind farm comprised of 25 wind turbines located near the city of Goldendale in Klickitat County, Washington, and related facilities (as more fully described below, the "Facility"), which was developed and constructed by Northwest Wind Partners, LLC and acquired by the Authority pursuant to an Asset Purchase Agreement, dated as of June 23, 2009 (the "Asset Purchase Agreement"), by and between the Authority and Northwest Wind Partners, LLC.

The Facility and the Asset Purchase Agreement

The Facility was developed and constructed by Northwest Wind Partners, LLC, a limited liability company organized and existing under the laws of the State of Delaware (the "Seller"). The Facility achieved commercial operation on June 30, 2010, and on September 14, 2010, the Authority completed its acquisition of the Facility from the Seller in accordance with the Asset Purchase Agreement.

The aggregate of rights, liabilities, interests and obligations of the Authority pursuant to the Asset Purchase Agreement, the Facility Purchase and Security Agreements and the other Project Agreements (as defined in the Power Sales Agreements), including, but not limited to, the Facility and all rights, liabilities, interests and obligations associated with the Facility and the Facility Output, and including all aspects of the operation and administration of the Facility and the Project Agreements and the rights, liabilities, interests and obligations associated therewith, constitute the Authority's "Linden Wind Energy Project" or the "Project."

The Project was acquired by the Authority for the purpose of providing the Participants with a long-term supply of renewable electric energy.

Power Sales Agreements and Contract for Sale and Purchase of Linden Wind Energy

General; Unconditional Payment Obligation. The Authority has sold entitlements to 100% of the Facility Output to the Participants pursuant to Power Sales Agreements, each dated as of August 1, 2009 (the "Power Sales Agreements"), with the Participants. Each Participant is a member of the Authority and is represented on the Authority's Board of Directors. Pursuant to the Power Sales Agreements, each Participant is entitled to a percentage of the Facility Output of the Project equal to its "Output Entitlement Share" as defined in the Power Sales Agreements and is obligated to make payments therefor in accordance with its Power Sales Agreement. The payments required to be made by each Participant under its Power Sales Agreements include the Participant's Output Cost Share and Indenture Cost Share of the Project, which include, among other things, its share of all of the Authority's Operating Expenses of the Project and the debt service on the Bonds and any other bonds issued by the Authority to finance or refinance the Project and other amounts required to be deposited into the funds and accounts established by the Indenture.

The Participants are obligated to make such payments for the Facility Output on a "take-or-pay" basis, that is, whether or not the Project or any part thereof is functioning, producing, operating or operable, or its output is suspended, interfered with, reduced or curtailed or terminated in whole or in part. In addition, such payments shall not be subject to any reductions and are not conditioned upon the performance or non-performance by any party of any agreement for any cause whatsoever. The payment obligations of the Participants under the Power Sales Agreements constitute operating expenses of their electric systems, payable solely from their respective electric system revenues (including available reserves). As operating expenses of their respective electric systems, the payment obligations of the Department under its Power Sales Agreement and all other of its "take-or-pay" contract obligations are payable on a parity with the Department's electric system revenue bonds and the payment obligations of Glendale under its Power Sales Agreement and all other of its "take-or-pay" contract obligations are payable prior to the payment of debt service on the revenue bonds of its electric system.

Output Entitlement Shares, Output Cost Shares and Indenture Cost Shares of the Participants. The following table sets forth the percentage entitlement (the "Output Entitlement Share") of each of the Participants with respect to the output of the Project, and their related Output Cost Share and Indenture Cost Share under the Power Sales Agreements.

Project Participants	**Output Entitlement Shares Output Cost Shares Indenture Cost Shares (Linden Wind Energy Project)[1]**
Department of Water and Power of the City of Los Angeles	90.0%
City of Glendale	10.0%

[1] The Department has contracted to purchase from Glendale its Output Entitlement Share of the Facility Output of the Project as described herein.

Contract for Sale and Purchase of Linden Wind Energy. Pursuant to a Contract for Sale and Purchase of Linden Wind Energy, dated as of August 1, 2009 (the "Contract for Sale and Purchase of Linden Wind Energy"), by and among Glendale, the Department and the Authority, the Department has purchased from Glendale, and Glendale has sold and assigned to the Department, Glendale's 10.0% Output Entitlement Share of the Facility Output for the term of Glendale's Power Sales Agreement, subject to the right of Glendale to repurchase all or a portion of such Facility Output at certain times and under certain circumstances (which rights of repurchase were not exercised and have since expired). Pursuant to the Contract for Sale and Purchase of Linden Wind Energy, in consideration for the purchase of Glendale's Output Entitlement Share of the Facility Output, the Department is obligated to pay to the Authority each month an amount equivalent to Glendale's share of the Monthly Costs for such Output Entitlement Share payable by Glendale under its Power Sales Agreement for such month. Such amounts received by the Authority from the Department constitute Revenues under the Indenture and will be applied in discharge of Glendale's obligations to pay its share of Monthly Costs under its Power Sales Agreement.

Management of the Project. Pursuant to the Power Sales Agreements, to the extent not inconsistent with the Facility Purchase and Security Agreements or other applicable Project Agreements, the Authority is responsible for the development, operation, maintenance and administration of the Project as provided in the Power Sales Agreements and described herein and in the Official Statement. Pursuant to the Power Sales Agreements and an Agency Agreement by and between the Authority and the Department, the Authority has appointed the Department as its agent for such purposes and as Project Manager on behalf of the Participants for the Project. In addition, a Coordinating Committee was established pursuant to the Power Sales Agreements to provide a liaison among the Authority and the Participants with respect to the Project, to administer the Asset Purchase Agreement and the other Project Agreements, to oversee the activities of the Project Manager, to approve budgets and to make recommendations with respect to the Project, including with respect to the development, operation and ongoing administration of the Project.

All actions taken by the Coordinating Committee require an affirmative vote of one or more Participants having Output Entitlement Shares aggregating at least 80%. However, the Power Sales Agreements provide that if a proposed action before the Coordinating Committee or the Authority's Board of Directors relates solely to the interests of a single Participant, and the other Participant determines, in good faith, that such proposed action will not adversely affect it, economically or otherwise, such other Participant shall not unreasonably withhold its affirmative vote with respect to such proposed action. In addition, in the event any vote is contemplated to be taken as to any Project Determination, the minority Participant shall be given notice of any proposed action, and its views, if any, shall be considered by the majority Participant prior to a vote on the proposed action. All actions with respect to the Project taken by the Authority's Board of Directors require an affirmative vote of at least 80% of the Project Votes (as defined in the Authority's Joint Powers Agreement) cast thereon.

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Operating Statistics

The operating results of the Project during the last five fiscal years are shown in the following table.

Southern California Public Power Authority
Linden Wind Project
Operating Statistics
(In Thousands)

	2020-21		2021-22		2022-23		2023-24		2024-25	
	Budget	**Actual**	**Budget**	**Actual**	**Budget**	**Actual**	**Budget**	**Actual**	**Budget**	**Actual**
Net Debt Service[(1)]	$10,116	$10,116	$10,140	$10,140	$9,264	$9,264	$8,856	$5,698	$9,912	$9,912
Lease Expense	600	444	600	664	600	601	600	599	600	433
O&M	2,400	1,208	2,160	2,137	1,848	2,888	1,848	2,384	3,652	3,026
SCPPA A&G	192	157	180	163	156	164	180	174	192	193
Wind Integration Charge	540	659	636	521	636	383	636	481	516	453
Generation Imbalance	0	(57)	0	(504)	0	(299)	0	(76)	0	140
Transmission/Exchange	3,000	2,597	3,000	3,284	3,000	5,823	3,204	4,964	7,995	6,493
Property Tax/Insurance	636	622	708	703	684	228	768	399	768	383
Total	$17,484	$15,746	$17,424	$17,108	$16,188	$19,052	$16,092	$14,623	$23,635	$21,033
MWHs	135,780	92,640	130,030	134,999	140,000	119,789	133,370	118,356	112,404	78,601
$/kWh	$0.129	$0.170	$0.134	$0.127	$0.116	$0.159	$0.121	$0.124	$0.210	$0.268

(1) Net Debt Service for Fiscal Years 2020-21, 2021-22, 2022-23, and 2024-25 includes additional budgeted and collected to pay future debt service.

Certain Financial Statements Relating to the Project

The following Statement of Net Position has been prepared by the Authority based upon audited financial statements of the Authority for the fiscal years ended June 30, 2025 and June 30, 2024.

Southern California Public Power Authority
Linden Wind Project
Statement of Net Position
(In Thousands)

	Fiscal Year Ended June 30, 2025	2024
ASSETS		
Noncurrent assets		
Net utility plant	$60,520	$66,333
Net lease asset	1,843	2,004
Investments – restricted	10,603	-
Investments – unrestricted	-	-
Total noncurrent assets	72,966	68,337
Current assets		
Cash and cash equivalents – restricted	2,543	333
Cash and cash equivalents – unrestricted	1,990	5,735
Interest receivable	134	12
Accounts receivable	255	67
Prepaid and other assets	101	96
Total current assets	5,023	6,243
DEFERRED OUTFLOWS OF RESOURCES		
Unamortized loss on refunding	2,297	2,527
Reclamation and decommissioning obligation	235	258
Total deferred outflows of resources	2,532	2,785
Total assets and deferred outflows of resources	$80,521	$77,365
LIABILITIES		
Noncurrent liabilities		
Long-term debt	$74,765	$74,765
Long-term lease liabilities	2,056	2,179
Reclamation and decommissioning obligation	880	857
Total noncurrent liabilities	77,701	77,801
Current liabilities		
Debt due within one year	-	-
Current portion of long-term lease liabilities	162	148
Advances from participants due within one year	10,102	2,004
Accrued interest	130	201
Accounts payable and accruals	3,671	2,408
Accrued property tax	137	138
Total current liabilities	14,202	4,899
Total liabilities	91,903	82,700
DEFERRED INFLOWS OF RESOURCES		
Unamortized gain on refunding	-	-
Total deferred inflows of resources	-	-

NET POSITION		
Net investment in capital assets	(12,323)	(6,228)
Restricted	-	-
Unrestricted	941	893
Total net position	(11,382)	(5,335)
Total liabilities, deferred inflows of resources and net position	$80,521	$77,365

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The following Statement of Revenues, Expenses and Changes in Net Position has been prepared by the Authority based upon audited financial statements of the Authority for the fiscal years ended June 30, 2025 and June 30, 2024.

Southern California Public Power Authority
Linden Wind Project
Statement of Revenues, Expenses and Changes in Net Position
(In Thousands)

	Fiscal Year Ended June 30,	
	2025	**2024**
Operating revenues:		
Sale of electric energy	$12,934	$23,343
Total operating revenues	12,934	23,343
Operating expenses:		
Operations and maintenance	10,883	8,758
Depreciation, depletion, and amortization	5,975	5,975
Decommissioning	23	23
Total operating expenses	16,881	14,756
Operating income (loss)	(3,947)	8,587
Non-operating revenues (expenses)		
Investment and other income	450	918
Inflation of decommissioning liability	(23)	(25)
Other interest and debt expense	(2,527)	(3,638)
Net non-operating revenues (expenses)	(2,100)	(2,745)
Change in net position	(6,047)	5,842
Net position – beginning of year	(5,335)	(11,177)
Net position– end of year	$(11,382)	$(5,335)

ESTIMATED DEBT SERVICE REQUIREMENTS FOR THE BONDS
(Cash Basis)

Year Ending July 1	2024 Series A Bonds Principal	Interest[1]	Total[2]
2026	-	$3,738,250	$3,738,250
2027	-	3,738,250	3,738,250
2028	-	3,743,399	3,743,399
2029	-	3,733,101	3,733,101
2030	-	3,738,250	3,738,250
2031	-	3,738,250	3,738,250
2032	-	3,743,399	3,743,399
2033	-	3,733,101	3,733,101
2034	-	3,738,250	3,738,250
2035	$74,765,000	3,738,250	78,503,250
Total[2]	$74,765,000	$37,382,500	$112,147,500

(1) Assumes that the Bonds will bear interest at 5.00% per annum from their delivery date through their final maturity date.
(2) Totals may not add due to rounding.

FINANCIAL STATEMENTS

The audited financial statements of the Authority, the Department, and Glendale for the fiscal year ended June 30, 2025 are attached hereto.

MISCELLANEOUS; MOST RECENT AUTHORITY OFFICIAL STATEMENT

The historical information set forth in this Annual Report is not necessarily indicative of future results or performance due to various factors, including, among others, those discussed in the Authority's Official Statement, dated July 9, 2025, relating to the Southern Transmission System Renewal Project, Revenue Bonds, 2025-1 (Fixed Rate Bonds) and Southern Transmission System Renewal Project, Revenue Bonds, 2025-2 (Fixed Tender Bonds – Term Rate Mode), under the section entitled "DEVELOPMENTS IN THE CALIFORNIA ENERGY MARKETS." Such Official Statement is on file with the Municipal Securities Rulemaking Board and is available to the public.

The Disclosure Resolution provides, in part, that under no circumstances shall any person or entity be entitled to recover monetary damages in the event the Authority fails to comply with the Disclosure Resolution. The Disclosure Resolution further provides that in the event of any such failure, only certain remedies may be available to Owners or Beneficial Owners. For a description of such remedies, see section 11 of the Disclosure Resolution set forth in Appendix C to the Official Statement.

CITY OF GLENDALE

The following is certain information concerning the City of Glendale ("Glendale" or the "City") and its electric system (the "Electric System"), prepared by Glendale for inclusion herein. This information does not purport to cover all aspects of the Electric System's business, operations and financial position.

General Description

The City is a charter city of the State. The City Charter provides for the creation of major departments, including the Glendale Water and Power Department ("Glendale Water and Power" or "GWP") which is responsible for construction, maintenance and operation of all public utilities owned or operated by the City, including the Electric System and a water system (the "Water System"). The General Manager of Water and Power administers Glendale Water and Power under the authority of the City Manager and is charged with the operation of both the Electric System and the Water System.

Glendale Water and Power provides water and electricity to nearly all the residential, commercial and industrial customers within the City limits. The funds and accounts of the Electric System and the Water System are held separately, and the funds and accounts of one system are not pledged to the other system's obligations.

Until 1937, Glendale purchased all of its electric energy from the Southern California Edison Company, successor to Pacific Light and Power Company, for distribution and sale to its customers. After the Boulder Canyon Project Act was approved by Congress in 1928, the City signed, in 1931, a contract with the United States for approximately 80,000 megawatt-hours ("MWh") of firm energy annually to be generated at the Hoover Dam. A contract was entered into at the same time with the City of Los Angeles to transmit this energy to Glendale at the maximum capacity of approximately 18 megawatts ("MW").

Studies made in 1938 showed that this firm allotment of Hoover Dam energy would not be sufficient for Glendale after 1942, with the result that Glendale established its own steam electric generating station located within the City, the Grayson Power Plant, with the first 20 MW unit being placed in service in 1941. This unit not only supplied energy to keep up with the growth of Glendale but also acted as standby to the transmission line from the Hoover Dam power plant. Since that time additional units owned by Glendale (and other resources) have supplied the energy requirements of Glendale.

The Electric System is interconnected with and in the Los Angeles Department of Water and Power Balancing Area. In 2024, the American Public Power Association recognized Glendale Water and Power as a Platinum Level Reliable Public Power Provider (RP3) for its service reliability, improvement programs, and safety performance.

The Electric System provides service to virtually all of the electric customers within the limits of Glendale, and has a service area of approximately 31 square miles and services an estimated population of approximately 192,212 as of January 1, 2025. For the Fiscal Year ended June 30, 2025, the customer base of the Electric System was comprised of approximately 78,071 residential customers, 13,458 commercial and industrial customers, and 21 other (governmental) customers.

Management of Glendale Water and Power

The Glendale City Council (the "City Council") has established the Glendale Water and Power Commission (the "Commission"), which is an advisory commission with the power and duty to make recommendations to the City Council: concerning (i) the operations and facilities of Glendale Water and Power and the need for changes or additions in its plant or in its operation; (ii) ways and means of financing changes and additions to the plant or the methods of operation; and (iii) changes of administrative policy which the commission deems desirable in order that Glendale Water and Power may better serve the people of Glendale. In addition, the Commission serves as an appellate board with respect to cases concerning energy and water meter tampering and water backflow prevention devices. The Commission may also exercise such other powers and duties as may be prescribed by ordinance not inconsistent with the City Charter.

The Electric System is under the direct management of the General Manager of Glendale Water and Power. Senior Management of Glendale Water and Power includes:

Scott K. Mellon, P.E. General Manager of Glendale Water and Power. Mr. Mellon began his engineering career in aerospace developing electrical subsystems for multiple aircraft such as reusable launch vehicles, stealth drones, and lighter-than-air platforms. Inspired by what he learned about software-based control systems and the potential for such systems in a smarter future electric grid, he joined Burbank Water and Power (BWP) in 2001. Mr. Mellon spent most of his tenure at BWP as a Principal Electrical Engineer and Project Manager in the Power Supply division, most recently managing an Advanced Distribution Management System implementation. Joining GWP in September 2022 as the Assistant General Manager – Power Management, Mr. Mellon brings significant experience working with 24-hour operations staff maintaining grid stability, implementing utility-scale energy projects, and overseeing renewable energy contract negotiations which are critical to meeting Renewable Portfolio Standards and City Council goals for carbon neutrality. Mr. Mellon was appointed General Manager of GWP in June 2025. Mr. Mellon has a Bachelor of Science in Electrical Engineering (BSEE) from University of California, Irvine where he earned a Specialization in Power System Design and was a team lead on a Hybrid Electric Vehicle Project competition. He is a licensed Professional Engineer in the State of California (since 2001) and holds a Leadership certificate from Woodbury University.

Chisom Obegolu, Chief Assistant General Manager, Water Services. Chisom Obegolu is the Chief Assistant General Manager of Water Services. He is responsible for managing the water operational and business functions, which includes system operations, planning and water resources management. He oversees Water Engineering, Water Operation, Water Distribution, and Water Quality. Among his primary duties is to implement the water strategic plan and initiatives. Mr. Obegolu previously worked for Glendora Water where he served as the Assistant Director of Water Services. During his tenure at Glendora, he led a city-wide comprehensive water infrastructure assessment including an integrated water resources master plan and cost of service study. He also worked for The Metropolitan Water District of Southern California, where he served as the Lead Engineer on several critical capital improvement projects, and a number of infrastructure reliability initiatives. Mr. Obegolu is a registered Civil Engineer in the State of California and earned a bachelor's degree in Civil Engineering from The University of Texas at San Antonio and a master's degree in Public Administration from California State University, Northridge.

Daniel Scorza, Chief Assistant General Manager, Electric Services. Mr. Daniel Scorza joined Glendale Water and Power in 2019 as the Chief Assistant General Manager – Electric Services. He oversees the Electrical Engineering and the Electrical Transmission & Distribution Operations and Construction sections. Mr. Scorza previously worked for LADWP for 36 years, and during his last 10 years there, he served LADWP as a Power Engineering Manager. He comes to GWP with a wealth of experience in areas such as utility engineering and system studies, operations, maintenance, corporate finance, corporate training, legislative matters, and engineering services contracts. Mr. Scorza has a Bachelors in Science degree in Electrical Engineering (electronics) from California State University – Los Angeles ("CSULA"), a Masters in Electrical Engineering degree (telecommunications/computer systems) from CSULA, a Masters in Electrical Engineering degree with an emphasis in Power Systems from University of Southern California (USC), and a Master's in Business Administration from the USC. Mr. Scorza is a registered Professional Electrical Engineer in the State of California.

Adrine Isayan, Assistant General Manager, Utility Finance and Risk Management. Mrs. Isayan joined GWP management in February 2024. She was previously the Assistant Director of Finance for the City. She has 26 years of experience working for the City's Finance Department. Throughout her career, she has worked in various capacities within the Finance Department, with the majority of her experience being in the City's Budget, Accounts Payable, and Payroll sections. Mrs. Isayan has significant experience in the preparation of financial forecasting and reporting. She has a dual Bachelor's degree in Information Systems and in Finance, both from California State University, Northridge.

David Davis, Utility Finance Manager. Mr. Davis has over 37 years in accounting, financial reporting, management reporting and 25 years of progressively responsible, professional, broad-based electric and water utility experience. As Utility Finance Manager, he is charged with full management responsibility for financial reporting, budgeting and regulatory reporting for both Water and Electric utilities. Mr. Davis holds a Bachelor's degree in Accounting from the University of Akron. Additionally, Mr. Davis is a Certified Public Accountant licensed in the State of California.

Glendale Water and Power Governance

The City Council acts as the Board of Directors of Glendale Water and Power. The City Council consists of five members, who serve four-year terms. Elections are held every two years, with three members up for election in one cycle and two members up for election in the next cycle. The mayor is chosen annually from among the council members to serve as mayor. The City Council's authority consists of, but is not limited to, establishing rates, approving budgets and approving the hiring of senior management.

The current members of the City Council and their terms are:

	Current Term Began	Current Term Expires
Ara Najarian, Mayor	March 2022	April 2026
Ardy Kassakhian, Councilmember	April 2024	June 2028
Daniel Brotman, Councilmember	July 2022	June 2026
Elen Asatryan, Councilmember	July 2022	June 2026
Vartan Gharpetian, Councilmember	April 2024	April 2028

Principal Existing Facilities; Resources Generally

Glendale owns facilities for the distribution of electric power, including approximately 56 miles of 34/69-kV power lines, 503 miles of 4/12-kV distribution lines and 12 distribution substations.

Glendale maintains a diverse resource mix, with capacity available from natural gas, nuclear generating units, coal, large hydroelectric and a range of renewable resources, totaling 284 MW as of June 30, 2025. The Grayson Power Plant generating station, which is located within the City, has been in service since 1941. The Grayson Power Plant is currently under repowering, with all units except for Unit 9 being demolished. Unit 9, a simple cycle natural gas-fired combustion turbine with 50.5 MW of gross nameplate capacity, began commercial operation in 2003. It is used to meet intermediate and peaking loads, and provides ancillary services such as operating reserve capacity and load balancing as required.

In January 2023, the City Council approved Scholl Biogas Renewable Generation Project. The project is for the installation of four gas engine generators, along with a landfill gas cleanup system with the purpose of capturing and combusting the existing landfill gas to produce approximately 11 MW of renewable energy. The generator units were installed in December 2024 with substantial completion expected to be achieved in July 2026.

In February 2023, the City Council directed staff to implement the Grayson Repowering Project. The Grayson Repowering Project consists of, in part, new facilities that have a total capacity of approximately 56 MW (three reciprocating internal combustion engines rated at 18.6 MW each) (the "Wärtsilä Power Island") and a 75 MW/300 MWh battery energy storage system. All engineering, procurement, and construction contracts have been executed. The anticipated commercial operation for the battery energy storage system is the beginning of August 2026. The Wärtsilä Power Island is delayed due to late equipment deliveries and at this time its commercial operation date is the third or fourth quarter of 2026.

Although the Grayson Power Plant is the largest source of capacity, the majority of Glendale's energy requirements are supplied by various long-term power purchase agreements and spot purchases to minimize supply cost, improve reliability and comply with California's mandates, including the Renewable Portfolio Standards ("RPS") and the Cap-and-Trade Program. Glendale has met RPS requirements for Compliance Period 1 (2011-2013), and Compliance Period 2 (2014-16), and Compliance Period 3 (2017-20). Glendale Water and Power is currently on track to reach the targets for Compliance Period 4 (2021-24), as well as preparing to meet the new targets under SB 100 of 60% RPS by 2030 and 100% carbon-free by 2045. Glendale has entered into a contract through the Southern California Public Power Authority ("SCPPA") for the purchase of 10 MW of small hydroelectric in the Northwest. The hydroelectric contract converts to ownership by Glendale when the related bonds are fully paid. In 2007, Glendale secured 16 MW of wind-powered energy from the Pebble Springs project. This contract is set to expire in 2027. Glendale also has a 9.5 MW long-term contract for small hydroelectric power delivered from the Tieton Hydro Dam, which is set to expire in 2029. Additionally, this agreement will convert to City ownership once the associated bonds are fully repaid.

In 2015, Glendale entered into a 25-year 50 MW firm energy supply with Skylar Resource, L.P., of which 50% will be renewable; this arrangement was modified to ensure 55% of the energy is renewable beginning 2020, and an additional 20% of the energy is carbon-free beginning in 2020. Skylar Resources, L.P. assigned the power purchase agreement to Townsite Solar LLC in 2021. In 2020, Glendale entered into a contract for the purchase of 3 MW from the Whitegrass No. 1 geothermal project, and 12.5 MW from Starpeak geothermal, as well as 25 MW of Solar Energy and 18.75 MW/75 MWh of Battery Energy Storage System from Eland I Solar and Storage. See also "–Power Supply" below. The Whitegrass No. 1 Geothermal Energy Project (Whitegrass) is a 4.0 MW nameplate geothermal energy project located in Lyon County, Nevada. In the Whitegrass Project, the developer is currently in default due to not providing a replenishment of the required performance security. The City is currently considering its options in this matter. However, this contractual default in Whitegrass is not anticipated to have a material effect on the City's finances or operations.

Although available resources under contract or owned by the City are sufficient to meet the City's current daily loads, a portion of the Electric System's energy supply is purchased on the wholesale hourly, daily and month-ahead spot markets.

Glendale is also currently developing other programs related to electric demand and supply. In 2020, the City Council authorized a contract with Lime Energy Services Company (now Wildan Energy Co.) for a 36,500 MWh/8.32 MW commercial energy efficiency program. The program has delivered 28,000 MWh of savings (78% of program goal) and load reduction of 2.8 MW (35% of program goal) in the first 3.5 years of the seven year program term. In November 2023, the City Council awarded two contracts for Phase 1 of the City Owned Solar Development Program. Motive Energy is currently conducting an environmental study for a ground mount solar project. Solar Optimum was awarded an Engineer, Procure, Construction contract for a rooftop or carport solar project on five sites. Total expected capacity for all six sites included in Phase 1 of the City Owned Solar Development Program is 4.9 MW. The GWP Perkins building roof top solar project was completed in March 2025 and the Central Library roof top solar project is scheduled for completion in December 2025. The Sports Complex and GWP's Utility Operations Center parking lot carpool solar projects are currently in the permitting process. The City continues to actively explore other local clean energy resources that can deliver energy, energy savings, storage and/or capacity to the City without utilizing GWP's transmission resources.

The following table sets forth the valuation of the Electric System facilities during the five Fiscal Years shown.

GLENDALE WATER AND POWER
ELECTRIC SYSTEM FACILITIES
($ in thousands)

	Fiscal Year Ended June 30,				
	2025	**2024**	**2023**	**2022**	**2021**
Utility Plant	$543,147	$539,734	$533,813	$615,413	$616,256
Less Accumulated Depreciation	(399,543)	(390,537)	(386,168)	(429,553)	(412,827)
Construction in Progress	418,945	162,863	29,695	9,086	8,075
Total Facilities	$562,549	$312,060	$177,340	$194,946	$211,504

Source: Glendale Water and Power.

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Power Supply

During the Fiscal Year ended June 30, 2025, the Electric System generated and purchased a total of 1,237,048 MWh. Sales to other utilities for the Fiscal Year ended June 30, 2025 were 104,008 MWh. Electric System peak demand in Fiscal Year ended June 30, 2025 was 348 MW. Over the five Fiscal Year period ended June 30, 2025, retail sales increased from 978,251 MWh to 993,009 MWh, an average annual increase of approximately 0.4%.

The following table sets forth the total power generated and purchased and the peak demand of the Electric System during the five Fiscal Years shown.

GLENDALE WATER AND POWER
TOTAL POWER GENERATED AND PURCHASED AND PEAK DEMAND

	Fiscal Year Ended June 30,				
	2025	**2024**	**2023**	**2022**	**2021**
Generated (MWh)	50,331	30,815	90,479	108,818	144,657
Purchased (MWh) [1]	1,186,717	1,219,048	1,392,077	1,371,399	1,410,514
Total Supply (MWh)	1,237,048	1,249,863	1,482,556	1,480,217	1,555,171
Retail Sales (MWh)	993,009	974,195	999,852	985,525	978,251
Sales to Other Utilities (MWh)[1]	104,008	224,585	397,991	419,063	482,809
System Peak Demand (MW)	348	287	329	261	335

(1) Fluctuations in purchased energy and sales to other utilities are a function of market conditions.
Source: Glendale Water and Power.

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The following table sets forth information concerning Glendale's power supply resources and the energy supplied by each during the Fiscal Year ended June 30, 2025.

GLENDALE WATER AND POWER
POWER SUPPLY RESOURCES
(as of June 30, 2025)

Source	Capacity Available (MW)	Actual Energy (MWh)[1]	Percent of Total Energy
Glendale-Owned Generating Facilities (Grayson):[2]			
Combustion Turbine Generators	50.5	50,331	4.07%
Joint Power Agency/Remote Ownership Interests:[3]			
Intermountain Power Project (IPA)	39	92,006	7.44%
Palo Verde Project	10	83,437	6.74%
Magnolia (SCPPA)	47	219,117	17.71%
Tieton (SCPPA)	7	7,572	0.61%
Purchased Power:[3]			
Hoover	20	46,531	3.76%
Pebble Springs Wind	20	41,093	3.32%
Skylar WSPP Renewables	50	289,482	23.40%
Star Peak	12.5	50,593	4.09%
Whitegrass No. 1	3	21,622	1.75%
Eland	25	68,791	5.56%
Market Purchases[4]	N/A	266,473	21.54%
Total	284	1,237,048	100.00%

(1) During the twelve-month period ended June 30, 2025.
(2) Rated or name-plate capacities. As of June 2024, the Grayson Power Plant is under repowering; all units were demolished, except for Unit 9.
(3) Entitlements, firm allocations and contract amounts.
(4) Market purchases are spot-market purchases.
Source: Glendale Water and Power.

Joint Powers Agency Resources/Remote Ownership Interests

As described below in various subsections, Glendale is a participant in many SCPPA projects. In addition, Glendale has long-term contract rights to capacity and energy in the Intermountain Power Project ("IPP") of the Intermountain Power Agency, a political subdivision of the State of Utah ("IPA") and in the Hoover Dam power plant, pursuant to contracts with the Western Area Power Administration ("Western"). See also "Indebtedness; Joint Powers Agency Obligations" below.

Certain of these projects in which Glendale has an entitlement interest or participation with other parties are subject to the other parties involved in those projects meeting their respective payment obligations with respect to such projects. If a party defaults on its payment obligations, then the non-defaulting parties, subject to the utilization of any reserves, may be required to expend additional funds with respect to such project. If a non-defaulting party does "step-up" to the payment obligation of a defaulting party, the non-defaulting party may ultimately be entitled to a portion of the capability and/or output of the defaulting party's share of the project.

These resources (including any sale and assignment of energy to another party, as described below under "–Indebtedness; Joint Power Agency Obligations – *Contingent Obligations for Wind Energy Projects*") are briefly described below.

Hoover Project Interest. Glendale is a contractor under Hoover Power Electric Service Contracts and holds an 18 MW share of the Hoover power capacity under Schedule A (referring to the original purchasers, including Glendale, under the Boulder Canyon Project Act of 1928), and a 2 MW share of capacity under Schedule B (referring to contractors, including Glendale, who advance-funded the Hoover power turbine uprating authorized in the 1984 Hoover Power Plant Act). The Hoover Project consists principally of 17 generating units at the hydroelectric power plant of the Hoover Dam, located approximately 25 miles from Las Vegas, Nevada. Modern insulation technology made it possible to "uprate" the nameplate capacity of existing generators (the "Hoover Uprating Project"). Glendale, along with the California cities of Anaheim, Azusa, Banning, Burbank, Colton, Pasadena, Riverside and Vernon obtained an entitlement to the capacity and allocated energy annually from the Hoover Uprating Project. In 1987, to reflect its entitlement, Glendale entered into contracts with the United States Bureau of Reclamation providing for the advancement of funds for the uprating and with Western for the purchase of power from the Hoover Uprating Project. Glendale is entitled to 20 MW or 1.0251% of the capacity and 1.5874% of the firm energy from the Hoover Project. Under normal hydrologic conditions, Glendale receives approximately 58,000 MWh of annual energy deliveries. In the Fiscal Year ended June 30, 2025, the Hoover Project provided 46,531 MWh of energy to Glendale.

The Electric Service Contracts for Hoover expired on September 30, 2017 and were replaced with new, 50-year Electric Service Contracts effective October 1, 2017. Pursuant to the Hoover Power Allocation Act of 2011, all Schedule A and Schedule B Hoover contractors, in each case including Glendale, have a right to continue to receive Hoover power for an additional term of 50 years, and five percent of Hoover's full rated capacity of 2.074 million kilowatts and associated firm energy was assigned to new Hoover allottees under new Electric Service Contracts that became effective on October 1, 2017. Glendale's share under the post-2017 Hoover Electric Service Contracts is 20.198 MW.

Palo Verde Nuclear Generating Station Interest. Through its membership in SCPPA, Glendale has a 4.40% entitlement interest (9.9 MW) in SCPPA's 5.91% ownership interest in the Palo Verde Nuclear Generating Station ("PVNGS"), including certain associated facilities and contractual rights, a 5.56% ownership in the Arizona Nuclear Power Project ("ANPP") High Voltage Switchyard and associated contractual rights, and a 6.55% share of the rights to use certain portions of the ANPP Valley Transmission System. Commercial operation and initial deliveries from PVNGS Units 1 and 2 commenced in 1986 and Unit 3 commenced in 1987. Transmission for PVNGS energy is provided to the City by the Mead-Adelanto Transmission Project and the Mead-Phoenix Transmission Project (see "Existing Transmission Resources" below) and agreements with Salt River Project, LADWP and Southern California Edison Company.

Glendale has a power sales agreement with SCPPA that obligates Glendale to pay for its share of capacity and energy on a "take-or-pay" basis, including debt service on bonds (if any, currently there are none) issued by SCPPA for the project, capital costs and costs related to operation and maintenance. In the Fiscal Year ended June 30, 2025, PVNGS provided 83,437 MWh of energy to Glendale.

The co-owners of PVNGS have created external accounts for the decommissioning of PVNGS at the end of its life. Based on the most recent estimate of decommissioning costs, SCPPA has advised Glendale that its estimated share of decommissioning costs through SCPPA is fully funded. No assurance can be given, however, that the amount accumulated to date will continue to be sufficient to fully fund SCPPA's share of decommissioning costs. SCPPA has advised Glendale that it anticipates it will receive a new estimate of decommissioning costs every three years.

San Juan Unit 3 Interest. Through its membership in SCPPA, Glendale has held a 20 MW (9.8%) entitlement in SCPPA's 41.8% interest in the San Juan Unit 3 and related common facilities of the San Juan Generating Station, a 4 unit, coal-fired electric generating station located in northwestern New Mexico, approximately 15 miles northwest of the City of Farmington, in San Juan County. As described below, Unit 3 was shut down on December 31, 2017, as part of an overall settlement of legal issues regarding emissions at the San Juan Generating Station.

In July 2015, with authorization from the City Council, SCPPA executed a San Juan Project Restructuring Agreement, a San Juan Decommissioning and Trust Funds Agreement and an Amended and Restated Mine Reclamation Agreement on behalf of Glendale and other SCPPA participants exiting from the San Juan project. These agreements allow for Glendale and certain other owners of the San Juan project to relinquish their ownership shares in San Juan and to contribute to the decommissioning and mine reclamation costs associated with the partial decommissioning of the coal plant. The agreements allow for the shutdown of two of the four San Juan units (Units 2 and 3) and provide for the installation of emissions-reducing equipment on the other two units (Units 1 and 4).

Glendale's and the other exiting parties' shares of the San Juan coal assets have been transferred to those participants remaining in the project after December 31, 2017. Glendale (through SCPPA) and other existing participants remain responsible for liability arising from operations before the December 31, 2017 date. Pursuant to the Mine Reclamation Agreement, SCPPA and the other project participants were obligated to set up a trust fund for the mine reclamation. Glendale's obligation after 2017 is defined by approximately 1.3% of the cost of reclaiming disturbances at the mine site as of December 31, 2017. Costs of plant decommissioning will be split between exiting participants and remaining participants.

Magnolia Power Project. Glendale is a participant of the Magnolia Power Project. The Magnolia Power Project is owned by SCPPA and was constructed and acquired for the primary purpose of providing participants in the Magnolia Power Project with firm capacity and energy to help meet their power and energy requirements. The Magnolia Power Project is operated by the City of Burbank. Glendale has a 16.5289% entitlement (40 MW base capacity and 47 MW peaking capacity) in the project through a long-term Project A Power Sales Agreement with SCPPA which obligates Glendale to pay for its share of capacity and energy on a "take-or-pay" basis, including debt service on bonds issued by SCPPA for the project, capital costs and costs related to operation and maintenance. The unit was placed in service in September 2005 and operates in a base-load mode (8,000 hours per year or more) with staffing by Burbank Water and Power personnel as SCPPA's operating agent on a 24-hour basis. In the Fiscal Year ended June 30, 2025, the Magnolia Project provided 219,117 MWh of energy to Glendale.

Tieton Hydropower Project. Glendale is a participant in SCPPA's Tieton Hydropower Project. Glendale has entered into a power sales and acquisition contract with SCPPA, under which SCPPA has sold to Glendale on a "take-or-pay" basis, its entitlement share of 50.0% (approximately 6.8 MW) of the capacity and energy of the Tieton Hydropower Project. Glendale's power sales and acquisition contract with SCPPA obligates Glendale to pay its share of debt service on bonds issued by SCPPA for the project, as well as capital costs and costs related to operation and maintenance. In the Fiscal Year ended June 30, 2025, the Tieton Hydropower Project provided 7,572 MWh of energy to Glendale.

IPA Intermountain Power Project Interest. The purpose of IPA is to provide for the financing, constructing and operation of the IPP. The IPP consists of: (a) a two-unit coal-fired, steam-electric generating plant with net ratings of 900 MW per unit (the "Intermountain Generating Station") and switchyard (the "Switchyard"), located near Lynndyl, in Millard County, Utah; (b) a ±500-kV direct current ("DC") transmission line approximately 490 miles in length from and including the Intermountain Converter Station (an alternating current ("AC")/DC converter station adjacent to the Switchyard) to and including a corresponding converter station at Adelanto, California (collectively, the "Southern

Transmission System" or "STS") (see "Existing Transmission Resources – *Southern Transmission System*" below); (c) two 50-mile, 345-kV AC lines from the Switchyard to the Mona Substation in the vicinity of Mona, Utah, and a 144-mile, 230-kV AC transmission line from the Intermountain AC Switchyard to the Gonder Substation near Ely, Nevada (collectively, the "Northern Transmission System" or "NTS"); (d) a microwave communications system; (e) a rail car service center located in Springville, in Utah County, Utah (the "Railcar Service Center"); and (f) certain water rights and coal supplies. Such 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."

IPP purchasers are 35 utilities consisting of Glendale and the California cities of Anaheim, Los Angeles, Riverside, Burbank and Pasadena; the 23 members of the IPA; and six rural electric cooperatives serving loads in the States of Utah, Arizona, Colorado, Nevada and Wyoming. Pursuant to a construction management and operation agreement between IPA and LADWP, LADWP acts as project manager and operating agent of the IPP, responsible for, among other things, administering, operating and maintaining the IPP. The facilities of the IPP have been in commercial operation since May 1987.

Glendale has entered into certain power purchase contracts with IPA and others to purchase certain entitlements of the IPP and related facilities, respectively. After accounting for transmission losses, for the Fiscal Year ended June 30, 2024, IPP contributed about 38 MW of capacity to Glendale. For the Fiscal Year ended June 30, 2025, IPP provided 92,006 MWh of energy to Glendale.

IPA possesses coal supply agreements to fulfill the supply requirement of approximately 900,000 tons in calendar year 2025. The coal was purchased under a portfolio of fixed-price contracts that lasted through August 2025. As a result of the decline in coal-fired generation around the nation, the coal market has constricted, especially in Utah, which has dramatically reduced supply in the region near IPA. The recent cost of coal delivered to the Intermountain Generating Station is similar to current market prices for the region. However, IPA expects the costs of any incremental coal purchases will increase due to the scarcity of coal in the Western United States and suppliers looking to other, longer-term buyers.

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 coal operation was shut down on November 26, 2025.

IPP Agreements. Glendale has two separate contracts with IPA and the Utah Participants (as defined below) in the IPP, which currently provide Glendale a 38 MW (2.165%) entitlement of this facility (the "IPP Agreements"). A summary of the IPP Agreements is as follows:

> *Original Entitlement* – Glendale contracted with IPA to purchase a 30 MW (1.704%) entitlement to the IPP plant. This contract obligates Glendale to pay its proportional share of the plant costs (including debt service and other fixed expenses), regardless of the amount of energy, if any, scheduled to Glendale, for the life of the facility.
>
> *Excess Power Sales Contract* – Glendale, the cities of Burbank and Pasadena, and LADWP (the "California Purchasers") contracted with 27 sellers (the "Utah Participants") and IPA (acting as agent for the sellers) to purchase a 379 MW (21.06%) entitlement of the IPP plant, which was deemed in excess of the sellers' needs. The California Purchasers agreed to divide the excess

among themselves in proportion to their original entitlements. Glendale's share of the excess is 8 MW (2.382%). This contract also provides for access to the NTS, which was built with IPA funds in order to deliver power from the IPP to the Utah Participants. The term of this contract extends until the IPA bonds are defeased or the sellers' load requirements meet certain specified conditions. The Utah Participants have the unilateral right to recall their original entitlements at any time.

IPP Repowering Project. The above-referenced IPP Agreements expire in 2027, but one of the key factors affecting the future of IPP is Senate Bill 1368, which became effective in January 2007, and prohibits any investment in baseload generation that does not meet specific emissions performance standards, subject to certain exceptions. In light of the restriction, in 2015, Glendale, along with each of the other 35 IPP participants, entered into Second Amendatory Power Sales Contracts, Renewal Power Sales Contracts, and Renewal Excess Power Sales Agreements with IPA. The Second Amendatory Power Sales Contract allows for the replacement of the coal-fired generation units at IPP with combined cycle natural gas-fired units (with a maximum design capacity of 1,200 MW), or an alternative repowering to include other technologies, if such alternative repowering is approved by at least 80 percent of the IPP participants (the "IPP Repowering Project"). In September of 2018, the IPP participants approved an alternative repowering project (the "IPP Alternative Repowering Project") which will reduce the size of the IPP Repowering Project to a maximum design capacity of 840 MW. The natural gas units were required to be permitted and commercially operational by July 1, 2025, though now projected to go into commercial service no later than December 2025. On November 5, 2019, the IPP Coordinating Committee adopted Resolution CC-2019-018, Confirmation of Commencement of Permitting, Construction and Installation of the Gas Repowering, confirming that the January 1, 2020 milestone has been met. Upon commercial operation of the new plant, the existing coal-fired plant would be decommissioned. SB 1368 and other recent legislation have caused Glendale to decrease its reliance on electricity generated by burning coal.

The Renewal Power Sales Contracts provided a process for IPP members to subscribe for shares of the new gas-fired or alternative repowering plant. On July 23, 2019, the City Council approved GWP's recommendation for continued participation in the IPP project which enabled Glendale to retain its 4.166% share of the project, providing Glendale 35 MW of generation and 122 MW of transmission from IPP. Glendale's current share of IPP generation provides approximately 7.4% of Glendale's energy needs.

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 its 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 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 of Utah 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 Utah H.B. 3004, IPA stated that Utah S.B. 161 would 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. 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 City cannot predict the impacts of the new legislation on the operation of IPP or the construction and operation of the IPP repowering project.

During its 2025 General Session, the Utah Legislature enacted Utah House Bill 70 ("Utah H.B. 70"). Utah H.B. 70 was submitted to the governor of Utah and the bill became effective upon the earlier of May 7, 2025, and the governor's approval of the bill.

Utah H.B. 70 requires IPA to maintain, indefinitely (i) power to station service for both of the coal units, (ii) an ongoing connection of one of its coal units to the IPP Switchyard, and (iii) interconnection and switchyard facilities that will allow the remaining coal unit to be interconnected with the IPP Switchyard without the need for a new interconnection request. Utah H.B. 70 also creates the Utah Energy Council for, among other purposes, the purposes of taking title to one or both of the coal units and assuming operational responsibility for each coal unit it acquires from IPA. Utah H.B. 70 also repeals the provisions of the Utah Code establishing the Utah Disposition Authority (effectively dissolving the Utah Disposition Authority) and the provisions specifying the functions that the Utah Disposition Authority was to have performed.

IPA is working with engineering personnel to reconfigure the proposed connections of synchronous condensers to the IPP Switchyard (connecting three synchronous condensers to the IPP Switchyard at one point of interconnection as opposed to two synchronous condensers at one point of interconnection and one synchronous condenser at another). IPA is constructing the synchronous condenser facilities to provide sufficient spinning mass to allow for operation of the natural gas units as designed and to maintain the rating of IPA's transmission facilities. IPA has indicated that it believes that it will be able to comply with the requirements of Utah H.B. 70, though such requirements will result in additional costs to IPA and will diminish the redundancy that would have resulted from having two points of interconnection for the synchronous condensers to the IPP Switchyard.

Purchased Power

In addition to City-owned resources and interests in the SCPPA, IPA and Hoover projects described above, the City has contractual arrangements for system firm purchases, primarily from renewable resources. Each of these resources is briefly described below.

Pebble Springs Wind Project. SCPPA, on behalf of Glendale and two other project participants, signed a long-term power purchase agreement with Pebble Springs Wind Project LLC. The facility is located in Oregon with a total capacity of 99 MW, comprised of 47 Suzlon 2.1 MW wind turbines. Glendale has a 20.264% (approximately 20 MW) entitlement interest in the total capacity, energy and environmental attribute rights produced by the facility. In the Fiscal Year ended June 30, 2025, Pebble Springs Wind Project provided 41,093 MWh of energy to Glendale.

Skylar Resources Firmed Renewable Purchase. In 2014, Glendale executed a 25-year agreement with Skylar Resources L.P. for the annual delivery of 292,000 MWh of energy to Glendale starting on December 1, 2015. In the Fiscal Year ended June 30, 2025, 289,482 MWh of energy was delivered to

Glendale. Deliveries may take place at the Mead Substation, Nevada-Oregon Broader (NOB), or another mutually agreed point. At least half of this energy must qualify each year as Portfolio Content Category 1 ("PCC 1") renewable energy under State law and regulations, and may be generated from a variety of renewable resources. The energy is delivered to Glendale Water and Power as a block from 6 a.m. to 10 p.m. every day. In November 2015, the transaction was bifurcated into two separate agreements: the first agreement was a four-year contract with Morgan Stanley Capital Group, Inc. from December 1, 2015 through December 31, 2019. The second agreement was a 21-year contract with Skylar from January 1, 2020 through November 30, 2040. In October 2017 the existing power purchase agreement was terminated and replaced with a 21-year Western Systems Power Pool ("WSPP") Power Purchase Agreement to increase renewable and carbon-free energy deliveries from 50% to 75%. In 2021, Skylar Resources L.P. assigned the power purchase agreement to Townsite Solar, LLC.

Whitegrass Geothermal Renewable Purchase. In 2020, SCPPA, on behalf of Glendale, signed a long-term power purchase agreement with Whitegrass No. 1, LLC for the annual delivery of 3 MW or approximately 23,000 MWh annually of renewable geothermal energy from the Whitegrass Geothermal Project located in Lyon County, Nevada. Glendale has a 100% entitlement interest in the total energy, capacity, and environmental attribute rights produced by the project. The deliveries began on April 1, 2020 and the contract ends on December 31, 2045. In the Fiscal Year ended June 30, 2025, Whitegrass Geothermal Project provided 21,622 MWh of energy to Glendale.

Star Peak Geothermal Renewable Purchase. In 2020, SCPPA, on behalf of Glendale, signed a long-term power purchase agreement with Star Peak Geothermal, LLC for the annual delivery of 12.5 MW or approximately 100,000 MWh annually of renewable geothermal energy from the Star Peak Geothermal Energy Project which will be developed in Pershing County, Nevada. Glendale has a 100% entitlement interest in the total energy, capacity, and environmental attribute rights produced by the project. The project started delivering power in September 2022, and the contract ends on December 31, 2045. In the Fiscal Year ended June 30, 2025, Star Peak Geothermal Project provided 50,593 MWh of energy to Glendale.

Eland I Solar and Storage Purchase. In December 2019, SCPPA, on behalf of Glendale and the Los Angeles Department of Water and Power, signed a 25-year power purchase agreement with 68SF 8ME, LLC for the purchase of renewable solar energy, battery energy storage system capacity, and environmental attribute rights from the Eland I Solar and Storage Center. The facility will be developed in Kern County, California. The energy will be delivered at Barren Ridge, and Glendale has entered into an agreement with the Los Angeles Department of Water and Power for the transmission of the energy to Glendale. Glendale has a 12.5% entitlement interest in the total capacity, energy, storage and environmental attribute rights produced by the facility, or 25 MW of renewable solar energy and 18.75 MW/75 MWh of battery storage capacity. The project began commercial operation on November 18, 2024. In the Fiscal Year ended June 30, 2025, Eland I Solar and Storage Project provided 68,791 MWh of energy to Glendale. Glendale is not a participant in phase II of the Eland project.

Fuel Supply

In the Fiscal Year ended June 30, 2025, Glendale generated approximately 4% of its electric energy requirements from local generating units which burn natural gas and are available for emergency operations and to provide operating reserves.

Glendale has firm contracts with respect to out of state transmission pipelines and gas supplies for 3,989 million British thermal units ("MMBtu") of natural gas per day. In addition, natural gas is purchased from the spot market at the Southern California Gas City-Gate. The Southern California Gas Company ("SCG") provides intrastate delivery of natural gas to Glendale's Grayson Power Plant and to the Magnolia Power Plant in Burbank.

Interstate Transportation. Natural gas is the primary fuel supply for Glendale's local generating requirements. Canadian natural gas is transported using Glendale's firm transportation on the TransCanada pipeline system and the PGT pipeline to the Pacific Gas & Electric Company ("PG&E") system at Malin (near the California-Oregon border), then into the SCG system at Wheeler Ridge (near Bakersfield, California) using Glendale's PG&E entitlement.

SCG provides transportation of gas to local generating plants from Topock on the east and from the PG&E expansion line terminus at Wheeler Ridge to the north. The current volumetric tariff rate is $2.5118 per MMBtu. There are a number of factors, including those described in the "Green Book" of the California Public Utilities Commission (the "CPUC") on natural gas industry restructuring, which could affect the tariff rate or fundamentally change Glendale's costs for intrastate gas transmission. In addition, intrastate transport costs are expected to increase due to pipeline safety investments by PG&E and SCG.

Biogas Renewable Generation Project. In November 2021, the City Council certified the EIR for the Biogas Renewable Generation Project. The project entails installation of generation units at the Scholl Canyon landfill site so that the landfill gas can be directly processed to generate energy at the Scholl Canyon site. The Scholl Canyon site is located in the City. The Biogas Renewable Generation Project has an estimated cost of $76 million and the project would be completed over a course of approximately 48 months. On January 24, 2023, the City Council approved a full notice to proceed for the second and final phase of the project. The project will have four Jenbacher gas engine generators that will generate approximately 11 megawatts of power. Per modeling done by the consultant on the future gas production and degradation of landfill gas after its closure, there will be sufficient gas production to run the proposed four engines until 2034, and three engines until 2042. During this time, the Biogas Renewable Generation Project will generate approximately 10.5 to 12 megawatts (four engines) and 7.7 to 9 megawatts (three engines) of gross renewable power. After 2042, there will be only two engines running and generating an estimated 6 megawatts of gross power. The anticipated commercial operation date is in June 2026.

Natural Gas Reserves Project. In June 2005, Glendale elected to participate in the Pinedale Natural Gas Project through SCPPA for up to 2,000 MMBtu per day. The project provides for the acquisition and development of gas resources, reserves, fields, wells, and related facilities to provide a long-term supply of natural gas for its participants. Glendale's share in the project is 4.2553%. The first acquisition by the project was completed on July 1, 2005 with the total cost to the participants (including LADWP which acquired its share directly and not through SCPPA) of $306.1 million, of which Glendale cash funded approximately $13 million for its share. The acquisition, located in Pinedale, Wyoming, is expected to provide Glendale with peak daily volume of between 700 to 900 MMBtu. In the Fiscal Year ended June 30, 2025, Glendale received peak daily volume of approximately 345 MMBtu. Glendale Water and Power has reserved $16 million to fund the drilling programs of the Pinedale property and for future acquisitions.

Prepaid Natural Gas Project. In October 2007, Glendale and several members of SCPPA completed a prepaid natural gas financing to secure another source of long-term supply of gas to provide fuel for the Magnolia Power Project and their other respective gas-fired generation stations. In connection with the prepaid natural gas financing, Glendale entered into a natural gas supply agreement with SCPPA pursuant to which Glendale purchases natural gas at a discount from the spot price over a term of 30 years (25 years as of a restructuring completed in 2009) which is scheduled to terminate at the end of October 2032. In the Fiscal Year ended June 30, 2025, this natural gas supply agreement provided approximately 29% of Glendale's gas requirements for the Grayson Power Plant and the Magnolia Power Project.

Existing Transmission Resources

Transmission resources are an integral component of Glendale's plan to provide economical and reliable electric service to its customers. Glendale currently has several firm capacity transmission agreements (ownership and long-term leases) to deliver up to 262 MW of remote generation to the Air Way Receiving Station in Glendale and to provide access to major hubs of the western wholesale power market. The transmission network currently allows Glendale to obtain energy supplies and enables sales and exchanges of energy during low load periods. Glendale has sufficient transmission resources during low-load periods, but during high-load periods must leverage local generation because of constrained transmission resources. Depending on the generation source, the energy is transmitted through a combination of the following transmission resources.

GLENDALE WATER AND POWER
FIRM TRANSMISSION SERVICE AGREEMENTS
(as of June 30, 2025)

Transmission Line/Path	Owner/Party	Glendale's Capacity	Primary Use
Pacific Northwest DC Intertie	Glendale	115 MW	NW Market
Northern Trans. System (NTS)	IPA/Utah	33/3 MW(1)	SW Markets
Southern Trans. System (STS)	SCPPA	55 MW	IPP
Victorville/Adelanto-Air Way	LADWP	112 MW	IPP, Hoover, PVNGS, SW Markets
Mead-Phoenix	SCPPA	41 MW	PVNGS, Westwing, Marketplace
Mead-Adelanto	SCPPA	112 MW	PVNGS, Marketplace
Sylmar-Air Way	LADWP	150 MW	NW and SW Markets
Burbank-Glendale Interconnection	Glendale/ Burbank	125 MW	Magnolia

(1) Glendale has rights to approximately 33 MW between IPP and Mona Substation and 3 MW between IPP and Gonder Substation. These rights vary by season and direction.
Source: Glendale Water and Power.

Pacific Northwest DC Intertie. Spanning 850 miles from Celilo in northern Oregon to Sylmar, California, the Pacific Northwest DC Intertie is a double-pole, +1-500 kV transmission line operated as a single path with separate ownership north and south of the Nevada-Oregon border ("NOB"). The Pacific Northwest DC Intertie conveys energy to Glendale from Pacific Northwest utilities and Glendale's interests in renewable energy projects in the northwest. Glendale is entitled to 115 MW (3.846%) of the total 3,100 MW capacity of the southern portion (south of the point where the line crosses the NOB of the Pacific Northwest DC Intertie). Because of the load diversity and excess hydroelectric energy in the spring during most years, the Pacific Northwest DC Intertie provides Glendale with opportunities for economical energy imports.

Northern Transmission System. The NTS consists of two 50-mile long 345-kV AC transmission lines which connect the IPP to the Mona Substation in Utah and the Gonder Substation in Nevada. Glendale has entitlements of 24 MW and 3 MW of capacity, respectively, on these transmission lines as a result of the IPP Excess Sales Contract with the Utah participants. These rights vary by season and according to the terms of the agreement. Under the IPP Repowering Project, Glendale has 0 MW of capacity on the NTS line.

Southern Transmission System. The Southern Transmission System ("STS") is a double-pole, +/- 500-kV DC transmission line spanning 488 miles from the IPP in central Utah to the Adelanto Substation in Southern California, together with an AC/DC converter station at each end. It is operated and maintained by LADWP under contract with IPA. In connection with its entitlement to the IPP, Glendale acquired a contractual entitlement to 44 MW (2.3%) of the total 1,920 MW capacity of the STS (prior to the upgrade, as described in the following paragraph) through a transmission system contract with SCPPA. Under the IPP Repowering Project, Glendale has 127 MW of capacity on the STS line.

To have access to potential renewable energy resource development available in central Utah and the Rocky Mountain region, and to have access to the potential energy in that area, the California participants in IPP initiated the STS Upgrade Project, which increased the transfer capability of the STS by 480 MW. The STS Upgrade Project increased the capacity of the Southern Transmission System from 1,920 MW to 2,400 MW, increasing Glendale's entitlement in the STS increased by 11 MW to 55 MW. Glendale has entered into a transmission service contract with SCPPA which obligates Glendale to pay the cost of its share of the transfer capability on a "take-or-pay" basis.

Southern Transmission System Renewal Project. In connection with the IPP Repowering Project, SCPPA is financing the costs of acquisition and construction of additional capital improvements to the Southern Transmission System (the "STS Renewal Project"), which initially will include new converter stations and AC switchyard expansions at the Adelanto Converter Station and the Intermountain Converter Station, and reactive power equipment. Glendale has entered into a renewal transmission service contract related to the STS Renewal Project. Under such an existing agreement with IPP and such renewal transmission service contract Glendale is obligated to pay the cost of its share of the transfer capability on a "take-or-pay" basis.

The Renewal Power Sales Contracts provided a process for IPP members to subscribe for shares of the new gas-fired or alternative repowering plant. On July 23, 2019, the City Council approved GWP's recommendation for continued participation in the IPP project which enabled Glendale to retain its 4.166% share of the project. Upon the expiration of certain original agreements in 2027, Glendale's share of the STS Renewal Project will be 5.278%.

Victorville/Adelanto-Air Way Transmission System. Glendale has contracts with LADWP for 112 MW of transmission capacity (net of losses) from either Adelanto or Victorville to the Air Way Receiving Station.

Mead-Phoenix Transmission Project, SCPPA Interest (Multiple Members). Glendale is a participant in SCPPA's member-related interest in the Mead-Phoenix Transmission Project, a 256 mile, 500-kV AC transmission line that extends between a southern terminus at the existing Westwing Substation (in the vicinity of Phoenix, Arizona) and a northern terminus at Marketplace Substation, a substation located approximately 17 miles southwest of Boulder City, Nevada. Glendale has entered into a transmission service contract with SCPPA under which SCPPA has sold to Glendale, on a "take-or-pay" basis, its entitlement share of 16.5% (approximately 41 MW) of SCPPA's member-related ownership interest in the Mead-Phoenix Transmission Project and which obligates Glendale to pay its share of debt service on bonds issued by SCPPA for the project, as well as capital costs and costs related to operation and maintenance.

Mead-Adelanto Transmission Project, SCPPA Interest (Multiple Members). Glendale is entitled to 112 MW (7.5%) of transmission capacity from the Mead-Adelanto Transmission Project, an approximately 202-mile, 500-kV AC transmission line that extends between a southwest terminus at the existing Adelanto Substation in southern California and a northeast terminus at Marketplace Substation, a substation located approximately 17 miles southwest of Boulder City, Nevada. Glendale has entered into a transmission service contract with SCPPA, under which SCPPA has sold to Glendale, on a "take-or-pay" basis, its entitlement share of SCPPA's member-related ownership interest in the Mead-Adelanto Transmission Project. Glendale's transmission service contract with SCPPA obligates Glendale to pay its share of debt service on bonds issued by SCPPA for the project, as well as capital costs and costs related to operation and maintenance.

Sylmar-Air Way. Glendale has two contracts with LADWP for 100 MW and 50 MW of firm transmission service from the Sylmar Receiving Station to the Air Way Receiving Station. These contracts are for the delivery of energy transmitted over the Pacific Northwest DC Intertie and for delivery of energy purchased from Southwest markets.

Sylmar Services Agreement. Glendale has a contract with LADWP for 115 MW of transfer rights through the Sylmar Switching Station into and out of the California Independent System Operator, which allow for the transfer of energy to/from the Pacific Northwest and to/from Glendale.

Glendale participates in energy markets of the California Independent System Operator (the "ISO") but currently does not intend to transfer control of its transmission resources to the ISO. Glendale has no firm plans to increase its transmission capacity.

Wholesale Transactions

In addition to making market purchases, Glendale sells wholesale energy, which includes electrical energy and capacity, ancillary services, transmission, renewable energy attributes, emission allowances, carbon allowances and carbon emission offsets, natural gas, transportation, imbalance and storage. When necessary, energy traders seek opportunities to market short-term energy transactions. All transactions are conducted within the Energy Risk Management Policy last approved by the City Council in May 2025.

Glendale's volume of short-term transactions on the electric wholesale market has fluctuated with market conditions in the western United States as have the revenues Glendale Water and Power has been able to realize by selling energy to third parties. Gross sales to third parties were $22,875,000 in Fiscal Year 2020-21, $29,862,000 in Fiscal Year 2021-22, $40,113,000 in Fiscal Year 2022-23, $20,666,000 in Fiscal Year 2023-24, and $15,044,000 in Fiscal Year 2024-25.

Interconnections and Distribution Facilities

Glendale's power system is inside the LADWP balancing area and is interconnected to the LADWP system at Air Way Receiving Station and to the Burbank system at Western Substation. Glendale owns facilities for the distribution of electric power to retail customers. These facilities include approximately 60 miles of 34/69-kV power lines, approximately 498 miles of 4/12-kV distribution lines (of which approximately 50% are underground), two switching substations, 12 distribution substations and 104 distribution feeders. The 69-kV Kellogg Switching station, a gas insulated station ("GIS"), includes state-of-the-art relays and devices. In 2011, one distribution substation was reconstructed from an air-insulated substation to GIS and converted from a 34.5/4-kV station to a 69/12-kV station. The project included conversion of 4 kV distribution services to 12 kV in the service area. In 2016, a second distribution substation was reconstructed from an air-insulated substation to GIS and converted from a 34.5/4-kV station to a 69/12-kV station. The project included conversion of 4 kV distribution services to 12 kV in the service area. In 2017, a 2 MW battery energy storage system was installed and connected to Kellogg 69-kV Switching Substation.

Electric Rates and Charges

Glendale is obligated by its Charter and the indenture of trust under which its Electric System bonds are issued to establish rates and collect charges in an amount sufficient to meet its expenses of operation and maintenance and debt service requirements (with specific requirements as to priority and coverage). Electric rates for Glendale are recommended by the Commission and are subject to approval by the City Council. Electric rates are not subject to regulation by the CPUC or by any other agency of the State of California (the "State"). The State Constitution requires that electric rates be based upon the cost of service to the various customer classes.

In addition, State Legislative Assembly Bill 1890 requires the imposition of a public benefits charge ("PBC") of 2.85% of annual revenue requirements. Beginning in January of 1998, Glendale collected this PBC as a 2.85% charge applied to all electric charges. In September of 1999, the City Council approved changes to the electric rates to collect the PBC beginning on January 1, 2000 as a charge per kilowatt hour ($0.002963 per kilowatt hour). In February of 2008, the City Council approved changes to the electric rates to collect the PBC beginning in March of 2008 as a percentage of the electric bill. The current rate is 2.85% of all electric charges.

For customers of the Electric System, the electric rates are composed of (i) a meter charge component, designed to cover a portion of the fixed costs of the Electric System, and (ii) an energy charge calculated based on usage. Some rate schedules are also subject to a demand charge and a reactive power charge. The electric rates also include bi-annual adjustable rates (made up of an Energy Cost Adjustment Charge and a Regulatory Adjustment Charge) which adjust the customer's electric bill upwards or downwards to reflect variation from the projected cost of purchased power, fuel and regulatory expenses. In addition, a Revenue Decoupling Charge (or Revenue Decoupling Credit) is applied to the customer's electric bill twice a year to reflect the variance from actual sales when compared to projected sales. Increases to the energy cost adjustment charge are limited to no more than one-half cent ($0.005) per kilowatt-hour during any 12-month period, except under limited circumstances such as an extended outage of a major resource or large and sustained fuel price increases, in which case the Energy Cost Adjustment Charge may be increased by up to an additional one cent ($0.01) per kilowatt-hour during any 12-month period.

The following table sets forth the average rates for the indicated customer classes for the Fiscal Years ended June 30, 2021 through June 30, 2025, including the Energy Cost Adjustment Charge, Regulatory Adjustment Charge, and Revenue Decoupling Charge (or Revenue Decoupling Credit, as applicable).

GLENDALE WATER AND POWER
FIVE-YEAR HISTORY OF ELECTRIC SYSTEM RATES
Average Rate – Dollars Per Kilowatt Hour

	Fiscal Year Ended June 30,				
Customer Class	2025	2024	2023	2022	2021
Residential	$0.3633	$0.2814	$0.2398	$0.2238	$0.2117
Commercial	0.2860	0.2538	0.2196	0.2056	0.2031
Industrial	0.2341	0.2043	0.1971	0.1801	0.1819
Lighting	0.0002	0.0002	0.0008	0.0008	0.0007

Source: Glendale Water and Power.

Between Fiscal Years 2018-19 through 2022-23, the Electric System's base rate has been increased four times. Due to the COVID-19 Pandemic, a 1% increase scheduled to become effective on July 1, 2020, was deferred one year by the City Council to July 1, 2021, and the subsequent two annual rate increases were also deferred by one year. The increased revenues from the rate increases in the base rates are intended to cover the rising costs of labor and materials and to further replenish the cash reserves.

In 2023, Glendale completed a rate study. The rate study was required to determine what if any rate increases might be needed to support the recently approved and proposed clean energy programs. The rate study also took into account the revised cost estimates for the Grayson Repower Project and the Biogas Renewable Project, as well as impacts COVID-19 may have on current and future electric sales and revenues. The rate study recommended overall system rate increases of 14.8%, 11.3% and 11.3% over three years, respectively. The City Council approved the series of rate increases in November 2023 that were to take effect January 1, 2024, July 1, 2024 and July 1, 2025, respectively. On June 3, 2025 the City Council approved a rate plan to defer the July 1, 2025 rate increases (scheduled to be 11.3% overall) to November 1, 2025 and reduce the increases to an overall system average of 5%. Additional increases to overall system rates were also approved at 2.95% effective on November 1, 2026 and 2.95% on November 1, 2027.

The City Council has an approved cash reserve policy for the Electric System. The currently approved level is $124.1 million. The cash reserve consists of moneys on deposit in an operating reserve, a contingency reserve, a rate stabilization reserve and a gas reserve. As of June 30, 2025, $124.1 million was designated.

The following table sets forth historical percentage increases in rates for the indicated customer classes per the Electric Rate Plan and in the rates approved in 2018 and in 2023. Such percentage changes do not reflect changes in the Fuel Adjustment Charge (prior to 2013) or in the Energy Cost Adjustment Charge, Regulatory Adjustment Charge, and Revenue Decoupling Charge (or Revenue Decoupling Credit, as applicable) (after 2013).

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GLENDALE WATER AND POWER
PERCENTAGE INCREASE IN ELECTRIC RATES

Effective	Overall System	Residential	Commercial	Industrial	Lighting
7/01/2007	8.1%	8.8%	7.1%	8.5%	0.0%
9/13/2013	8.0	8.8	7.2	7.9	0.0
7/01/2014	7.0	7.7	6.3	6.9	0.0
7/01/2015	5.0	5.5	4.5	4.9	0.0
7/01/2016	2.0	2.2	1.8	2.0	0.0
7/01/2017	2.0	2.2	1.8	2.0	0.0
7/01/2018	0.0	0.0	0.0	0.0	0.0
7/01/2019	0.5	3.2	(1.0)	(1.2)	0.0
7/01/2020[1]	0.0	0.0	0.0	0.0	0.0
7/01/2021	1.0	3.2	(0.3)	(0.5)	0.0
7/01/2022	1.0	3.1	(0.4)	(0.3)	0.0
7/01/2023	1.0	3.0	(0.3)	(0.4)	0.0
1/01/2024	14.8	18.6	9.7	12.1	0.0
7/01/2024	11.3	14.0	7.5	9.4	0.0
11/01/2025	5.0	6.1	3.3	4.2	0.0
11/01/2026	2.95	3.6	2.0	2.5	0.0
11/01/2027	2.95	3.6	2.0	2.5	0.0

(1) In June 2020, the City Council deferred the scheduled July 1, 2020 increase by one year to July 1, 2021, and deferred the subsequent two annual rate increases by one year.

(2) On June 3, 2025 the City Council approved a rate plan to defer the July 1, 2025 rate increases (scheduled to be 11.3% overall) to November 1, 2025 and reduce the increases to an overall system average of 5%. Additional increases to overall system rates were also approved at 2.95% effective on November 1, 2026 and 2.95% on November 1, 2027.

Source: Glendale Water and Power.

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Customers, Energy Sales, Revenues and Demand

The average number of customers, MWh sales and revenues derived from sales, by classification of service, during the past five Fiscal Years, are listed below.

GLENDALE WATER AND POWER
ELECTRIC SYSTEM
CUSTOMERS, SALES, REVENUES AND DEMAND

	Fiscal Year Ended June 30,				
	2025	**2024**	**2023**	**2022**	**2021**
Number of Customers:					
Residential	78,071	77,563	77,188	76,929	76,757
Commercial	13,275	13,221	13,184	13,140	13,108
Industrial	183	183	185	193	193
Other (Government)	21	21	21	21	21
Total	91,550	90,988	90,578	90,283	90,079
Megawatt-Hour Sales:					
Residential	384,218	375,266	402,751	381,594	400,862
Commercial	311,450	304,966	307,505	310,816	294,782
Industrial	288,131	284,737	280,350	283,930	273,434
Public Street & Highway Lighting	9,210	9,226	9,245	9,185	9,173
Total Retail Energy Sales	993,009	974,195	999,852	985,525	978,251
Sales to Other Utilities[1]	104,008	224,585	397,991	419,063	482,809
Total Energy Sales	1,097,017	1,198,780	1,397,843	1,404,588	1,461,060
Revenues from Sale of Energy:					
Residential	$139,602,000	$105,618,000	$96,598,000	$85,439,000	$ 84,866,000
Commercial	86,172,000	74,409,000	64,563,000	61,001,000	56,915,000
Industrial	67,463,000	58,172,000	55,248,000	52,586,000	49,740,000
Public Street & Highway Lighting	2,908,000	3,002,000	2,961,000	2,933,000	2,961,000
Sales to Other Utilities[1]	15,044,000	20,666,000	40,113,000	29,862,000	22,875,000
Total Energy Sales	$311,189,000	$261,867,000	$259,483,000	$231,821,000	$217,357,000

(1) Fluctuations in sales to other utilities revenues were due primarily to changing market demand.
Source: Glendale Water and Power.

For the Fiscal Year ended June 30, 2025, approximately 47% of Glendale's electric sales revenues were derived from sales to residential customers, while industrial and commercial customers represented approximately 23% and 29% of sales revenues, respectively. Additional revenues, other than retail sales, were generated from sales to governmental agencies, and sales to other utilities.

Within Glendale, large commercial and industrial customers are principally institutions and large corporations (such as hospitals, entertainment companies, and high-rise office buildings). No single large commercial/industrial customer accounted for more than 3% of total electric sales revenues during the Fiscal Year ended June 30, 2025. The top 10 industrial customers represented approximately 14% of total electric sales revenues during the Fiscal Year ended June 30, 2025.

Capital Requirements

Glendale currently expects capital requirements for the Electric System for the current and next four Fiscal Years to aggregate approximately $364 million. This includes capital requirements such as the Grayson Repowering Project and the Biogas Renewable Generation Project at the Scholl Canyon site. See "Electric Rates and Charges" above. It is expected that these requirements will be funded from a combination of revenues, bond proceeds and cash reserves of the Electric System. The Grayson Repowering Project is projected to require since inception $640 million in capital expenditures through Fiscal Year 2026-27. The Biogas Renewable Generation Project is expected to require $76 million in capital expenditures over a two-year period starting in Fiscal Year 2023-24.

The following table lists the expected yearly capital requirements of the Electric System for the five Fiscal Years indicated.

GLENDALE WATER AND POWER
ELECTRIC SYSTEM
CAPITAL REQUIREMENTS
($ in Thousands)

Fiscal Year	Capital Requirements*
2026	$274,111
2027	33,447
2028	26,025
2029	15,225
2030	15,225
Total	$364,033

* Includes Grayson Repowering Project and Biogas Renewable Generation Project.
Source: Glendale Water and Power.

Insurance

Glendale carries property insurance through Arthur J. Gallagher Insurance Company for Glendale Water and Power. The property insurance policy covers "All Risk of Direct Physical Loss or Damage including Flood, excluding Earthquake." Current deductibles range from $25,000 to $250,000. Sub-limits apply to various specific components of this coverage.

Glendale is self-insured and administered for workers' compensation claims. Funding for this protection is provided through an Internal Service Fund. Glendale carries an excess workers' compensation insurance policy with a $2 million self-insured retention. Glendale is also self-insured for unemployment insurance, general auto and public liability through separate Internal Service Funds. Glendale carries an excess liability insurance policy with a $2 million self-insured retention and a $27 million limit. A claims payable liability has been established in these funds based on a case-by-case basis with estimates of reported claims and an estimate for claims incurred but not reported. Management of Glendale believes that provisions for claims at June 30, 2025 are adequate to cover the net cost of claims incurred to that date. However, such liabilities are, by necessity, based upon estimates and there can be no assurance that the ultimate cost will not exceed such estimates.

Transfers to the General Fund

The City Charter provides that the credit balance, if any, or any part thereof, in the Electric Works Revenue Fund at the end of any Fiscal Year (that is, the amount of which is in excess of the amount of all outstanding demands and liabilities unpaid from said fund on account of budget appropriations therefrom), shall be transferred to the Glendale Water and Power Surplus Fund. The Charter also provides that at the end of each Fiscal Year, up to 25% of the operating revenues of Glendale Water and Power for such Fiscal Year, excluding receipts from power supplied to other cities or utilities at wholesale rates, shall be transferred from the Glendale Water and Power Surplus Fund and further transferred to the City's General Reserve Fund; provided, however, that the City Council, on an annual basis, may reduce or eliminate the amount to be transferred if the City Council determines that such reduction or elimination is necessary to assure the sound financial position of Glendale Water and Power.

Since the Fiscal Year ended June 30, 2021, the Electric System has transferred between $17.5 million and $29.6 million per year from the Electric Works Revenue Fund to the City's general fund. Glendale's Fiscal Year 2025-26 budget includes a transfer of $ 32.6 million from the Electric Works Revenue Fund to the City's general fund.

Indebtedness; Joint Powers Agency Obligations

Electric System Revenue Bonds. As of December 1, 2025, in addition to joint powers agency obligations, Glendale had $595 million in outstanding principal amount of long-term obligations payable from net revenues of the Electric System (after the payment of operating and maintenance expenses of the Electric System, including Glendale's obligations with respect to its agreements with joint powers agencies as described under "– *Joint Powers Agency Obligations*" below) consisting of (i) $47,050,000 in outstanding principal of Electric Revenue Bonds, 2016 Refunding Series; (ii) $164,560,000 in outstanding principal of Electric Revenue Bonds, 2024 Series, (iii) $49,760,000 in outstanding principal of Electric Revenue Bonds, 2024 Refunding Series, (iv) $165,480,000 in outstanding principal of Electric Revenue Bonds, 2024 Second Series and (v) $168,235,000 in outstanding principal of Electric Revenue Bonds, 2025 Series.

Joint Powers Agency Obligations. As previously discussed, the City is a participant in the following SCPPA projects: the Palo Verde Nuclear Generating Station Project (of which no bonds are outstanding), the Southern Transmission System Project, the STS Renewal Project, the Mead-Phoenix Transmission Project, the Mead-Adelanto Transmission Project, the San Juan Unit 3 Project (which was shut down on December 31, 2017, and of which no bonds are outstanding), the Magnolia Power Project, the Prepaid Natural Gas Project, the Natural Gas Project (but the City has no obligation to pay debt service on the Natural Gas Project bonds), the Tieton Hydropower Project, the Linden Wind Energy Project, the Windy Point Project and the Milford Wind Corridor Phase II. See "– Joint Powers Agency Resources/Remote Ownership Interests." To the extent the City participates in projects developed by SCPPA, the City is obligated to pay for its proportionate share of the cost of the particular project (see, however, "– *Contingent Obligations Wind Energy Projects*" below for a discussion of certain costs now covered by LADWP). In addition, the City has entered into certain power sales contracts with IPA and others for the delivery of electric power from the Intermountain Power Project.

Agreements of the City with SCPPA (other than the agreement relating to SCPPA's Prepaid Natural Gas Project bonds) and IPA are on a "take-or-pay" basis, which requires payments to be made whether or not projects are completed or operable, or whether output from such projects is suspended, interrupted or terminated. Such payments represent the City's share of current and long-term obligations.

Payment for these obligations is expected to be made from operating revenues received during the year that payment is due. All of these agreements (other than the agreements relating to SCPPA's Prepaid Natural Gas Project bonds) contain "step-up" provisions obligating the City to pay a share of the obligations of any defaulting participant. The City's participation and share of the principal obligations of SCPPA and IPA (without giving effect to any "step-up" provisions) are shown in the following table.

GLENDALE WATER AND POWER
OUTSTANDING IPA AND SCPPA OBLIGATIONS
(as of December 1, 2025)

	Outstanding Debt	City's Participation[1]	City's Share of Principal Amount of Outstanding Debt[2]
IPA			
Intermountain Power Project	$ 112,520,000	2.044%	$2,299,507
Renewal Project	1,695,130,000	4.167	70,636,067
SCPPA			
STS Project	72,190,000	2.274	1,641,601
STS Renewal Project	1,790,705,000	5.278	94,513,410
Magnolia Power Project[3]	187,770,000	17.254	32,397,836
Prepaid Natural Gas Project	219,555,000	23.000	50,497,650
Tieton Hydropower Project..........................	26,585,000	50.000	13,292,500
Linden Wind Energy Project........................	74,765,000	10.000	7,476,500[4]
Windy Point Project/Windy Flats …..……	126,675,000	7.630	9,665,303[5]
Milford Wind Corridor Phase II..................	52,135,000	4.902	2,555,658[6]
TOTAL	$4,358,030,000		$284,976,032

(1) Participation obligation is subject to increase upon default of another project participant (other than with respect to SCPPA's Prepaid Natural Gas Project bonds).
(2) Does not include interest on the debt.
(3) Excludes bonds relating solely to City of Cerritos.
(4) LADWP has purchased from Glendale its 10.0% output entitlement share and has agreed to pay costs associated therewith.
(5) LADWP has purchased from Glendale its 7.630% output entitlement share and has agreed to pay costs associated therewith.
(6) LADWP has purchased from Glendale its 4.902% output entitlement share and has agreed to pay costs associated therewith.
Source: Glendale Water and Power; IPA.

For the Fiscal Year ended June 30, 2025, Glendale's payments of debt service on its joint powers agency obligations aggregated approximately $5.7 million. Annual debt service on Glendale's joint powers agency obligations is expected to increase to approximately $25 million due to the Intermountain Power Renewal Project. This projection assumes no additional future debt issuances. Unreimbursed draws under liquidity arrangements supporting joint powers agency variable rate debt obligations bear interest at a maximum rate substantially in excess of the assumed rates stated above and may be subject to repayment to the liquidity provider over a significantly shorter period than the originally scheduled payment of principal on the related bonds. Interest rate swap agreements entered into by joint powers agencies in connection with hedged variable rate joint powers agency obligations may be subject to early termination. In the event of early termination of a joint powers agency interest rate swap agreement, the joint powers agency could be obligated to make a substantial payment to the applicable swap provider a corresponding amount of which termination payment (proportionate to each project participants' participation share in the related project) could be due from the applicable project participants.

Contingent Obligations for Wind Energy Projects. Glendale has entered into three power sales agreements with SCPPA, under which SCPPA has sold to Glendale on a "take-or-pay" basis, its entitlement share of the capacity and energy in three separate projects; those being (i) an entitlement share of 10.0% of the Linden Wind Energy Project, which consists of the acquisition by SCPPA of an approximately 50 MW nameplate capacity wind powered electric generating facility comprised of 25 wind turbines located near the town of Goldendale in Klickitat County, Washington, including the structures, facilities, equipment, fixtures, improvements and associated real and personal property and other rights and interests necessary for the ownership and operation of the generation facility and the sale of energy therefrom, (ii) an entitlement share of 4.902% of the Milford Wind Corridor Phase II Project, which consists of the purchase by SCPPA of all energy generated by a 102 MW nameplate capacity wind powered electric generating facility comprised of 68 wind turbines located near Milford, Utah, for a term of 20 years (unless earlier terminated), and (iii) an entitlement share of 7.630% of the Windy Point/Windy Flats Project, which consists primarily of the purchase by SCPPA of all energy generated by a 262.2 MW nameplate capacity wind powered electric generating facility comprised of 114 wind turbines and related facilities located in the Columbia Hills area of Klickitat County, Washington near the City of Goldendale, for a term of 20 years (unless earlier terminated). Under each power sales agreement Glendale is obligated to pay its share of debt service on bonds or notes issued by SCPPA for each such project, as well as certain capital and other costs related to operation and maintenance.

In connection with each of the aforementioned projects, Glendale, SCPPA and LADWP entered into power sales agreements wherein LADWP purchased from Glendale, and Glendale sold and assigned to LADWP, Glendale's output entitlement share of each such project for the term of Glendale's respective power sales agreement with SCPPA. Pursuant to each such contract, LADWP agreed to pay to SCPPA each month during the term of the respective contract, an amount equivalent to Glendale's share of the monthly costs payable by Glendale under its respective power sales agreement with SCPPA for such output entitlement share for such month, and such amounts received by SCPPA from LADWP are applied to discharge Glendale's obligations to pay such share of monthly costs under each respective power sales agreement. In addition, Glendale's other obligations under each power sales agreement with SCPPA are discharged to the extent, but only to the extent, that such obligations are performed by LADWP. Except as discharged as provided in the respective agreements, the obligations of Glendale to pay monthly costs and to perform its other obligations under each power sales agreement with SCPPA are not otherwise affected and the power sales agreement continues as an obligation of Glendale.

Historical Operating Results and Debt Service Coverage

The following table shows the historical operating results and debt service coverage on Glendale's outstanding Electric System bonds during the five Fiscal Years ended June 30, 2021 through June 30, 2025. The information relating to the Fiscal Years ended June 30, 2021 through June 30, 2025 was prepared by Glendale on the basis of its audited financial statements and information derived from its audited financial statements.

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GLENDALE WATER AND POWER
ELECTRIC SYSTEM
HISTORICAL OPERATING RESULTS AND DEBT SERVICE COVERAGE
($ in thousands)

	Fiscal Year Ended June 30,				
	2025	**2024**	**2023**	**2022**	**2021**
Operating Revenues					
Revenues	$327,688	$261,867	$259,483	$231,821	$217,357
Other Revenues Available for Debt Service[1]	31,176	32,683	18,409	6,371	13,961
Total Revenues Available for Debt Service	$358,864	$294,550	$277,892	$238,192	$231,318
Operating Expenses[2]					
Production[3]	$171,683	$142,589[4]	$190,083	$145,451	$141,136
Transmission & Distribution	52,377	46,312	47,884	34,657	38,428
Customer Accounting & Sales	10,223	8,869	9,689	12,070	8,340
Total Expenses	$234,283	$197,770	$247,656	$192,178	$187,904
Net Income Available for Debt Service	$124,581	$96,780	$30,236	$46,014	$43,414
Debt Service[5]	$26,642	$12,173	$12,167	$12,168	$12,071
Debt Service Coverage[6]	4.68x	7.95x	2.49x	3.78x	3.60x

(1) Other revenues available for debt service include interest revenues plus other non-operating revenues less other non-operating expenses excluding interest expenses. Does not include contributions in aid.
(2) Operating expenses exclude depreciation, gas depletion, capital expenditures and transfers to Glendale's general fund (which transfers are payable after the payment of debt service).
(3) Includes generation, fuel, purchase power and labor expenses.
(4) Production costs for the Fiscal Year ended June 30, 2024 are lower than the two prior Fiscal Years due to (i) operation of a single unit of the Grayson Power Plant, as all units except for Unit 9 were taken offline as of June 30, 2023 in preparation for demolition; (ii) moderate weather during the summer months of 2023; and (iii) lower natural gas prices in the spot markets relative to prior Fiscal Years.
(5) Represents debt service on Glendale's outstanding Electric System revenue bonds.
(6) Increase in Debt Service Coverage for the Fiscal Year ended June 30, 2024 due to decrease in production costs, and increase in interest income and rates.

Source: Glendale Water and Power.

The following Statement of Net Position information for the five Fiscal Years ended June 30, 2021 through June 30, 2025 has been prepared by Glendale based upon audited financial statements.

GLENDALE WATER AND POWER
ELECTRIC SYSTEM
STATEMENT OF NET POSITION
($ in thousands)

	Fiscal Year Ended June 30,				
	2025	2024	2023	2022	2021
ASSETS					
Current assets:					
Pooled cash and investments	$254,951	$ 97,111	$85,662	$136,560	$149,657
Cash with fiscal agent	37,537	25,926	2,543	2,332	2,538
Investment with fiscal agent	2,398	2,398	2,398	2,398	2,398
Interest receivable	2,722	1,661	1,709	1,422	1,063
Investment Gas/Electric Commodity	7,023	9,023	8,018	-	-
Pooled Restricted cash and investments	-	64,947	-	-	-
Accounts receivable, net	39,478	35,317	28,314	33,063	31,889
Inventories	20,615	12,809	11,484	9,704	9,401
Prepaid items	10,195	31,953	28,652	8,565	8,381
Total current assets	374,919	281,145	168,780	194,044	205,327
Non-current assets:					
Capital assets:					
Land	6,306	6,306	6,306	6,306	6,306
Natural gas reserve	22,178	22,176	22,175	22,171	22,166
Buildings and improvements	63,770	63,758	63,970	73,722	73,716
Machinery and equipment	449,716	446,307	440,728	512,684	513,741
Intangible assets	1,088	975	422	327	327
Less: accumulated depreciation	(382,495)	(374,182)	(370,730)	(414,831)	(398,901)
Natural gas depletion	(16,362)	(15,811)	(15,162)	(14,481)	(13,770)
Amortization	(686)	(544)	(276)	(241)	(156)
Construction in progress	418,945	162,863	29,695	9,086	8,075
Lease assets	89	212	212	203	-
Total capital assets	562,549	312,060	177,340	194,946	211,504
Pooled designated and invested cash	154,412	151,354	151,435	124,100	124,100
Restricted cash	12,306	51,626	44,463	41,417	24,032
Leases receivable	911	941	993	1,016	-
Total non-current assets	730,178	515,981	374,231	361,479	359,636
Total assets	1,105,097	797,126	543,011	555,523	564,963
Deferred outflows of resources related to pensions	14,045	22,153	25,077	8,898	9,569
Loss on refunding	2,865	3,093	3,391	3,627	3,863
Deferred outflows of resources related to OPEB	281	350	408	467	496
Total assets and deferred outflows of resources	1,122,288	822,722	571,887	568,515	578,891
LIABILITIES AND NET POSITION					
Current liabilities:					
Accounts payable	$110,486	$ 45,097	$29,236	$19,250	$12,035
Interest payable	8,893	4,765	2,447	2,572	2,691
Bonds payable, due in one year	14,658	10,900	7,431	7,126	6,841
OPEB liability	54	69	-	-	-
Deposits	2,557	2,224	1,726	1,355	1,277
Total current liabilities	136,648	63,055	40,840	30,303	22,844
Noncurrent liabilities:					
Bonds payable	472,466	301,125	126,097	133,529	140,655
Leases and subscriptions payable	300	376	86	125	-
OPEB liability	1,051	1,096	1,781	2,156	2,632
Net pension liability	67,312	73,326	72,144	37,753	68,975
Total noncurrent liabilities	541,129	375,923	200,108	173,563	212,262
Total liabilities	677,777	438,978	240,948	203,866	232,474
Deferred inflows resources related to pensions and OPEB	6,190	8,048	4,986	23,090	334
Total liabilities & deferred inflows of resources	683,967	447,026	245,934	226,956	235,440
Net position[(1)]:					

Net investment in capital assets	19,102	59,209	43,249	61,184	72,099
Restricted For					
Carbon Emissions	10,255	50,949	37,160	26,718	17,443
Restricted investment	-	-	-	7,281	919
Low carbon fuel standard	2,051	677	1,634	1,749	-
SCAQMD emission controls	-	-	5,669	5,669	5,669
Unrestricted	406,913	264,861	238,241	238,958	247,321
Total net position	$438,321	$ 375,696	$325,953	$341,559	$343,451

(1) In 2021, a prior period adjustment of $2,398,000 was made to decrease the beginning net position of the Electric Utility. In prior years, the OPEB liability was only recorded in the governmental activities, because of the immateriality of the allocated liability to the enterprise funds. In Fiscal Year 2020-21, due to the decrease in the discount rate, the OPEB liability increased and it became a material liability in the Electric Utility.

Source: Glendale Water and Power.

Employees of Glendale Water and Power

For the Fiscal Year ended June 30, 2025, Glendale Water and Power budgeted for approximately 328 full-time employees. Most Electric System employees are represented by the Glendale City Employees Association ("GCEA"), the International Brotherhood of Electrical Workers ("IBEW") and the Glendale Management Association ("GMA") in all matters pertaining to wages, benefits and working conditions. The GCEA and the GMA each entered into a memorandum of understanding with the City that will expire on June 30, 2027. Glendale has recognized Local 18 of IBEW as the exclusive representative of approximately 117 of the 245 full-time Electric System employees. The contract with IBEW, which was approved in January 2024, expires on July 31, 2027.

Wildfire Mitigation Measures

Approximately 62% the City encompasses geographical areas classified by CPUC fire threat maps as "Tier 2" or "Tier 3" fire-threat areas (i.e., areas of elevated or extreme risk from utility-associated wildfires). However, many of these areas do not contain any Electric System assets that could ignite a wildfire and many others are required to be managed by the property owners to be cleared for hazardous vegetation. The remaining areas that contain Electric System assets and that are not areas required to be managed by private owners constitute approximately 0.47% of the City's total area.

The City currently has undertaken a number of wildfire mitigation measures. These include:

- The City responds to red flag wind warnings issued for the area by the National Weather Service by de-energizing (without loss of customer load) the transmission line of the Electric System that runs across uninhabited hilly terrain with elevated fire risk. In addition, GWP is looking into employing the broken conductor technology and fast acting protection scheme to mitigate the risk of fire furthermore.

- The City has installed fire resistant wrap/coating poles in high fire risk locations and has installed covered conductors (in selected Tier 2 areas).

- The City expanded vegetation management to exceed minimum clearance requirements by trimming trees down to the telecommunications level.

- The City installed devices to minimize the risk of fire in brush areas from ejecting a blown fuse.

- To evaluate the effectiveness of its wildfire plan, the City developed metrics posted on an internal website to track the number of electrical assets replaced in Tier 2 and Tier 3 areas.

- The City expanded asset inspections and refined its master plan to address end-of-life infrastructure management and mitigate against fire risks from downed power lines or failed equipment that can spark and ignite wildfires. This inspection / assessment program includes pole inspections, vault inspections, and inspections of all assets connected to (or within) these assets, including (but not limited to) transformers, crossarms, insulators, conductors, cables, landings, capacitor banks, voltage regulators, and all other attachments. In addition to assessing the condition of Electric System assets, the program provides a mechanism to prioritize repair and replacement projects.

State fire-threat maps and fire-threat areas are revised from time to time. In March 2025, the California Department of Forestry and Fire Protection (hereinafter, "CalFire") released updated wildfire hazard severity zone maps for the Southern California region. These updated maps identify areas as "moderate," "high," and "very high" wildfire hazard severity zones in "local responsibility areas," where local fire departments are responsible for responding to fires, in order to reflect zones in California that are susceptible to wildfires. The updated maps increase the acreage in the City that is identified as a "very high" wildfire hazard severity zone and add identified areas of "moderate" and "high" wildfire hazard severity zones (which categories were not previously included in earlier versions of the CalFire fire hazard severity zone maps). These wildfire hazard severity zone maps differ from the CPUC Fire-Threat Maps referenced above. The CPUC Fire-Threat Map is designed specifically for identifying areas where there is an increased risk for utility associated wildfires. The updated CalFire wildfire hazard severity zone maps are being evaluated by the Department for their impact on future wildfire mitigation plans.

Litigation

General. At any given time, including the present, there are certain claims and disputes that arise in the normal course of the Electric System's enterprise activities. Such matters could, if determined adversely to Glendale or the Electric System, affect expenditures by Glendale, and in some cases, its Electric System revenues. The management of the GWP is of the view that no pending actions are likely to have a material adverse effect on Glendale's ability to pay its Electric System obligations.

Grayson Litigation

On March 18, 2022, the Sierra Club filed a Petition for Writ of Mandate against the City in the matter of *Sierra Club v. City of Glendale, et al.*, Los Angeles Court Case No. 22STCP00983. The Sierra Club petition challenged the City Council's February 15, 2022 certification of a Final Environmental Impact Report (an "FEIR") for the proposed Grayson Repowering Project and authorizations to move forward with various Grayson Repowering Project development activities. The case went to trial and on July 31, 2023, the trial court issued a statement of decision denying Sierra Club's petition. On October 30, 2023, Sierra Club filed a notice of appeal. The hearing on Sierra Club's appeal was held on September 3, 2024 in the California Court of Appeal. On November 27, 2024, the Court of Appeal issued a statement of decision affirming the trial court's judgment in favor of the City. The Sierra Club did not file a request for further review and therefore the litigation has concluded in favor of the City.

In a related case that the Los Angeles Superior Court coordinated with the Sierra Club matter, on March 21, 2022, the Glendale Residents Against Environmental Destruction ("GRAED") filed a Petition for Writ of Mandate against the City (*Glendale Residents Against Environmental Destruction v. City of Glendale, et al.*, Los Angeles Court Case No. 22STCP01021) also challenging the City Council's February 15, 2022 certification of an FEIR for the proposed Grayson Repowering Project and authorizations to move forward with various Grayson Repowering Project development activities. On July 31, 2023, the trial court issued a statement of decision denying GRAED's petition and entered a judgment denying the petition on August 28, 2023. GRAED filed a timely notice of appeal. The hearing on GRAED's appeal was held on September 3, 2024 in the California Court of Appeal. On September 30, 2024, the Court of Appeal issued its decision denying GRAED's appeal and upholding the trial court's decision. GRAED did not file a request for further review and therefore the litigation has concluded in favor of the City.

THE DEPARTMENT OF WATER AND POWER OF THE CITY OF LOS ANGELES

The following is information concerning The Department of Water and Power of the City of Los Angeles (in this section, the "Department") and such Department's Power System, prepared by the Department for inclusion herein. This information does not purport to cover all aspects of the business, operations and financial position of the Department or the Power System. A copy of the most recent audited financial statements of the Power System (the "Department's Power System Financial Statements") may be obtained from John Equina, Chief Accounting Employee and Assistant Auditor of the Department of Water and Power of the City of Los Angeles, 111 North Hope Street, Room 465, Los Angeles, California 90012, and is also available on the Electronic Municipal Market Access ("EMMA") website of the Municipal Securities Rulemaking Board ("MSRB"), currently located at http://emma.msrb.org. The Department's Power System Financial Statements are incorporated herein by this reference. However, other information presented on such website or referenced therein other than the Department's Power System Financial Statements is not part of this Annual Report and is not by reference to such website incorporated herein.

THE DEPARTMENT

General

The Department is the largest municipal utility in the United States and is a proprietary department of the City of Los Angeles (the "City"). Control of Power System assets and funds is vested with the Board of Water and Power Commissioners of the City of Los Angeles (the "Board"), whose actions are subject to review by the City Council of the City (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 470 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.

Los Angeles 2025 Wildfire Event

Beginning on January 7, 2025, a severe fire fueled by windstorms originated in the Pacific Palisades neighborhood (the "Palisades Fire") of Los Angeles County, which is part of the City. On January 7, 2025, the Mayor declared a local emergency throughout the City and the Governor of California (the "State") proclaimed a State of Emergency with respect to the Palisades Fire. According to the California Department of Forestry and Fire Protection, almost 24,000 acres were burned in the Palisades Fire, with an estimate of more than 7,800 structures damaged or destroyed in the affected areas, as well as the loss of several lives.

As a result of such declarations and subsequent federal action, funding from the Federal Emergency Management Agency ("FEMA") is generally available to the City with respect to its recovery efforts, including for certain costs of restoring facilities damaged as a result of the disaster to their pre-disaster condition, and to those affected by the Palisades Fire.

The City is also pursuing cash flow loans in accordance with recently enacted Assembly Bill No. 100 that allows for the Governor's Office of Emergency Services ("CalOES") to provide zero interest loans for FEMA reimbursable work, to be repaid with funding from FEMA as work is completed and submitted to FEMA for reimbursements. The City has submitted five loan requests to CalOES totaling approximately $45 million and anticipates submitting additional loan requests on a rolling basis.

The Department has estimated the costs of damage to Power System facilities and infrastructure (including costs of damage to certain joint system facilities) from the Palisades Fire to be approximately $89 million as of September 2025. Additionally, approximately $8 million of costs related to windstorm damage was incurred. This estimate is inclusive of physical damages to Power System facilities, which largely consists of damage to electric distribution stations and equipment and Department-owned street and outdoor lighting, and an increase in operating expenses of the Power System primarily related to overtime for field crews and other support staff and increased materials and equipment costs associated with repairs of the damaged infrastructure. These estimates are preliminary and are expected to change as the damage assessment and recovery efforts continue and developments occur. The longer term impacts or changes to the costs, expenses or capital improvement plans of the Department as a result of the fires are not yet known.

To alleviate financial burdens for people impacted by the Palisades Fire, the Department paused billing for customers whose homes or businesses were damaged or destroyed by the fire until September 5, 2025. Beginning on September 6, 2025, the Department resumed billing customers in the Pacific Palisades for water and electric service. In addition, collection processes and disconnections for non-payment have been suspended until December 31, 2025 in the affected areas. The impacted areas represent approximately 0.7% of the Department's Power System customer accounts and approximately 0.8% of annual Power System electric sales revenues. Service has been restored to nearly all homes and businesses in the affected areas that are able to receive electric service.

The City continues to recover from the Palisades Fire. As of December 8, 2025, debris removal was 99.8% complete and the City has entered the intermediate phase of recovery. There also may be long-term impacts of the Palisades Fire on the City's fiscal condition and the local economy.

Multiple lawsuits have been filed, including two putative class actions (and additional lawsuits continue to be filed) against the City, the Department, and other entities by people claiming damage from the Palisades Fire. Pursuant to an order of the judge overseeing the litigation, on October 8, 2025, plaintiffs liaison counsel (*i.e.*, counsel appointed to organize the plaintiffs) filed a master complaint (the "Master Complaint") containing allegations that are intended to be common to some or all of the cases. The Master Complaint brings claims relating to the Water System, the Power System and certain vacant lots owned by the City. With respect to the Water System, the Master Complaint asserts claims for inverse condemnation and nuisance. With respect to the Power System, the Master Complaint asserts claims for inverse condemnation, dangerous condition of public property, and nuisance. The doctrine of inverse condemnation is a "takings clause" cause of action under the State and federal constitutions that entitles property owners to just compensation if their private property is damaged by a public use. California courts have imposed liability on public agencies in legal actions brought by private property holders for damages, where the inherent risks in the public agency's infrastructure, as deliberately designed, constructed or maintained, are determined to be a substantial cause of damage to the property. The Master Complaint also alleges dangerous condition of public property and nuisance claims related to vegetation management on certain lots owned by the City.

The existing lawsuits, as of December 8, 2025, consist of a number of state court actions (approximately 91 cases) filed on behalf of approximately 2,361 individual plaintiffs, including two cases filed as putative class actions on behalf of an individual and all those similarly situated that seek to certify as a class all individuals and entities in the areas impacted by the Palisades Fire who suffered property damage, loss of use, evacuation, or other harm as a result of the Palisades Fire. The cases are pending in the Los Angeles Superior Court. The existing lawsuits, as consolidated under the Master Complaint, generally allege, among other things, that: (1) the Department failed to properly maintain its water system for the purpose of fighting fires (and specifically that it failed to properly maintain the Santa Ynez Reservoir and, in certain of such cases, the Chautauqua Reservoir), (2) the Department chose to design its water system for urban use, not to fight wildfires, (3) after the fire ignited, power poles broke and the Department failed to de-energize its distribution and transmission electrical facilities, which resulted in its overhead power lines arcing and causing additional fires, and (4) the Palisades Fire was foreseeable in light of data about the history of fires in the area, current fire risk and weather. The Master Complaint also alleges that the City did not clear brush from vacant lots in Pacific Palisades, including on lots that are owned by the City, and that embers landed on this brush, sparking spot fires. The plaintiffs are seeking compensation for damages including, but not limited to, lost or damaged property, lost income or wages, and attorney's fees, and in certain of the cases loss of use/marketability of property, emotional distress, and punitive damages. Some of the pending actions seek certain injunctive relief as well as monetary damages.

The cases are not yet at a stage where it is possible to reasonably estimate the potential ultimate financial exposure to the City or the Department. Most of the filed lawsuits do not contain a specific dollar amount, although one of the pending class actions asserts a damages figure of greater than $10 billion. The City and the Department deny all liability claims. The City and the Department intend to vigorously defend against all of these lawsuits, and any others that may be filed. However, the City and the Department are unable to assess at this time whether additional claims will be asserted by the plaintiffs, the likelihood of success of the plaintiffs' cases or any possible outcome. There can be no assurances that additional causes of action will not be asserted by the current plaintiffs when they adopt the Master Complaint, or additional litigation will not be brought by other plaintiffs whose properties were damaged in the Palisades Fire. Complaints filed before the filing of the Master Complaint allege other causes of action and additional theories of liability, which certain plaintiffs may choose to maintain as part of their adoption of the Master Complaint.

See also "LITIGATION" for a discussion of this litigation and the status thereof.

A number of investigations and reviews of the fire events and of local agency preparation and response actions are being undertaken, including a Congressional investigation, an independent review at the direction of the Governor, an investigation and after-incident review by the Los Angeles Fire Commission, and reviews and investigations by other federal, State and local agencies.

The federal Bureau of Alcohol, Tobacco, Firearms and Explosives (the "ATF") led the investigation into the cause of the Palisades Fire. The Department provided information to the ATF and other agencies in connection with their investigations. The ATF examined the Department's overhead transmission facilities that are near, but outside of, the area where the Palisades Fire reportedly ignited. As of December 8, 2025, neither the ATF nor any other investigating authority has issued a formal cause and origin report identifying the source of the Palisades Fire (the ATF has indicated that it has completed its report). However, on October 8, 2025, the United States Department of Justice announced the arrest of Jonathan Rinderknecht, whom the United States charged in a criminal complaint with the destruction of property by means of fire. Specifically, Mr. Rinderknecht is alleged to have started the Lachman Fire in the Pacific Palisades area on the morning of January 1, 2025. According to an affidavit of an ATF special agent investigating the fire (the "ATF Affidavit") that was provided in connection with the criminal complaint against Mr. Rinderknecht, the multi-agency investigation into the origin and cause of the Palisades Fire determined that the Palisades Fire was a "holdover" fire (*i.e.*, a continuation of the Lachman Fire that began on January 1, 2025). The ATF Affidavit expressly ruled out power lines as a potential cause of the Lachman Fire. No investigating authority has asked the Department to preserve any of its electrical facilities in the area.

On October 15, 2025, a federal grand jury indicted Mr. Rinderknecht on one count of destruction of property by means of fire, one count of arson affecting property used in interstate commerce, and one count of timber set afire. Mr. Rinderknecht's trial is set for April 21, 2026.

See also "FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY– California Climate Change Policy Developments – *Legislation and Court Action Relating to Wildfires*."

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. There is currently one vacancy on the Board. The current members of the Board are:

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 degree 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.

ALLAN T. MARKS, *Commissioner*. Mr. Marks was appointed to the Board by Mayor Karen Bass and confirmed by the City Council on December 10, 2025. Mr. Marks is a lawyer and strategic advisor with a focus in international project finance, energy and infrastructure. He advises boards of directors, senior executives, investors, fund managers and other organizations on corporate strategy, risk management, market and regulatory changes, and capital formation, particularly in connection with the energy transition, renewable energy, innovative clean technologies, geopolitics, financial innovation, climate risks, resilience, and sustainability. As a lawyer, Mr. Marks has handled complex energy and infrastructure transactions in the United States, Canada, Latin America, Asia and Europe with an aggregate value of over $100 billion. Mr. Marks teaches at both the University of California, Berkeley School of Law and the UCLA School of Law, where he is Affiliated Faculty at the Emmett Institute on Climate Change and the Environment and the Lowell Milken Institute for Business Law and Policy. He is also a Senior Fellow at the Columbia Center on Sustainable Investment, a center of Columbia University's Climate School, a Non-Resident Visiting Senior Fellow at New York University's SPS

Center for Global Affairs, and a Distinguished Scholar in Energy Law and Sustainability and Professorial Lecturer in Law at the George Washington University Law School. He previously taught Energy and Infrastructure Project Finance at the University of California, Berkeley for 12 years at both the Law School and the Haas School of Business. Mr. Marks is a Contributor to Forbes. He speaks and publishes frequently on energy, infrastructure, business strategy, financial markets, climate change, public policy, regulatory trends, and international transactions. Mr. Marks served for 11 years as the founding co-chair of the State Bar of California's Subsection on Public-Private Infrastructure. He is a member of the Pacific Council on International Policy and served on Law360's Project Finance Editorial Board. He also serves as a board director of the Colburn School and other civic organizations. Mr. Marks received his Bachelor of Arts degree in international studies from The Johns Hopkins University and his Juris Doctorate from the University of California, Berkeley School of Law.

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.

BENNY B. TRAN, *Commissioner*. Mr. Tran was appointed to the Board by Mayor Karen Bass and confirmed by the City Council on December 3, 2025. Mr. Tran previously served as Executive Vice President of Corporate Strategy at the Los Angeles Football Club (the "LAFC"), where he was part of the founding team and helped shape the club's business strategy, sustainability efforts, and government relations. He played a central role in the development and launch of the club's $375 million stadium, contributing to environmental compliance and initiatives that achieved LEED Gold certification. He also partnered with the Department on energy-efficiency design and EV-charging programs that positioned the venue as one of the City's leading examples of sustainable sports infrastructure. Mr. Tran has more than 15 years of experience advancing sustainability, public policy, and major infrastructure initiatives across the U.S. and Asia. Prior to his work at the LAFC, Mr. Tran worked across Southeast Asia on climate and development initiatives. With the Clinton Climate Initiative, he led energy-efficiency and clean-energy programs in major cities including Ho Chi Minh City, Hanoi, Bangkok, Manila, and Jakarta. He later advised the Asian Development Bank and World Bank on establishing Vietnam's first Climate Innovation Center to strengthen the region's green-technology ecosystem. Earlier in his career, he also supported public-health system strengthening as part of the Clinton Health Access Initiative. Mr. Tran recently served as a City Commissioner for the Los Angeles Department of Recreation and Parks, contributing to governance, capital planning, and community-access priorities. He is also a board member of Food Access Los Angeles, a Fulbright Scholar, and a Center for Arabic Study Abroad (CASA) Fellow. Mr. Tran holds a master's degree in public and international affairs from Princeton University and a Bachelor of Arts degree in Middle Eastern Studies from Emory University.

Management of the Department

The management and operation of the Department are administered under the direction of the General Manager. 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, 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.

JOHN A. SMITH, *Chief Administrative Officer*. Mr. Smith was named Chief Administrative Officer of the Department on July 1, 2024. In this capacity he oversees support organizations that service both Water and Power Systems. He has 36 years of experience with the City of Los Angeles, including 25 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 37 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, *Senior Assistant General Manager of the Power System*. Mr. Hanson was named Senior Assistant General Manager of the Power System in December 2024 after serving as Interim Senior Assistant General Manager of the Power System since August 2024. Mr. Hanson has 23 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.

ANDREW VIRZI III, *Assistant Chief Financial Officer and Controller*. Mr. Virzi was named Assistant Chief Financial Officer and Controller of the Department in December 2024 after serving as the Assistant Retirement Plan Manager for the Water and Power Employees Retirement Plan since May 2024. He previously served as the Manager of Accounts Payable, Taxes and Travel from December 2021 through May 2024. Prior to that, Mr. Virzi was the Manager of Cost of Service from July 2019 through December 2021. He has over 15 years of experience with the Department, beginning his career in August 2010. Mr. Virzi holds a bachelor's degree in accounting from California State University, Northridge and holds a master's degree in business administrations from Pepperdine University. He is a certified public accountant in the State.

JOHN EQUINA, *Chief Accounting Employee and Assistant Auditor*. Mr. Equina was named Chief Accounting Employee and Assistant Auditor of the Department in May 2025. He also serves as the Assistant Chief Financial Officer and Treasurer of the Department and the Director of Finance and Risk Control Division, roles to which he was named in March 2025. Before serving in these roles, Mr. Equina served as the Assistant Director of Finance and Risk Control Division of the Department since March 2021. He has over 21 years of financial management experience in debt management, risk control, accounting, and auditing. Mr. Equina holds a bachelor's degree in accounting from San Beda University in the Philippines. He also has a master's degree in business administration from Pepperdine University. Mr. Equina is a certified public accountant in the State.

Employees

As of August 31, 2025, the Department assigned approximately 5,531 Department employees to the Power System on a full time basis. Approximately 4,226 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 approximately 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 terms of the existing memoranda of understanding will continue to govern until successor agreements are executed. 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 (10) 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 70% 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 described below for the Fiscal Year ending June 30, 2026 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 (10)(d), the Power System made contributions to the Retirement Plan of approximately $296 million in Fiscal Year 2024-25 (as part of a total Department contribution of approximately $434 million), and the Power System made contributions to the Retirement Plan of approximately $295 million in Fiscal Year 2023-24 (as part of a total Department contribution of approximately $432 million). For the Fiscal Year ended June 30, 2025, the Department budgeted a contribution of approximately $296 million to be paid from the Power Revenue Fund to the Retirement Plan (as part of a total Department budgeted contribution of approximately $435 million). For the Fiscal Year ending June 30, 2026, the Department has budgeted a contribution of approximately $244 million to be paid from the Power Revenue Fund to the Retirement Plan (as part of a total Department budgeted contribution of approximately $358 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. For more information about the Department's pension liabilities as reported in accordance with GASB No. 68, see Note (10) and "Required Supplementary Information" of the Department's Power System Financial Statements.

According to the latest actuarial valuation and review of the Retirement Plan that was completed by The Segal Company on September 23, 2025, as of July 1, 2025, the market value of the assets in the Retirement Plan was approximately $19.5 billion, which results in an overfunded actuarial accrued liability (based on the market value of assets) of approximately $672.0 million; the actuarial value of the assets in the Retirement Plan as of such date was approximately $18.9 billion, which would result in an overfunded actuarial accrued liability (based on the actuarial value of assets) of approximately $98.1 million. As of July 1, 2025, the Retirement Plan had an unrecognized investment gain of approximately $574.0 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 gain for the year ended June 30, 2025 were recognized immediately in the actuarial value of assets, the aggregate required contributions to the Retirement Plan for Fiscal Year 2025-26 would remain equal to the normal cost of 16.0% of payroll due to the surplus position of the plan as of July 1, 2025. Additionally, if the net deferred gain 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, 2025 would increase from approximately 100.5% to approximately 103.6%.

According to the actuarial valuation and review of the Retirement Plan that was completed by The Segal Company on October 1, 2024, as of July 1, 2024, the market value of the assets in the Retirement Plan was approximately $17.8 billion, which results in an unfunded actuarial accrued liability (based on the market value of assets) of approximately $214.0 million; the actuarial value of the assets in the Retirement Plan as of such date was approximately $17.6 billion, which would result in an unfunded actuarial accrued liability (based on the actuarial value of assets) of approximately $426.2 million. As of July 1, 2024, the Retirement Plan had an unrecognized investment gain of approximately $212.0 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 gain for the year ended June 30, 2024 were recognized immediately in the actuarial value of assets, the aggregate required contributions to the Retirement Plan for Fiscal Year 2024-25 would decrease from approximately 28.0% of total Department covered payroll to approximately 26.6% of total Department covered payroll. Additionally, if the net deferred gain 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, 2024 would increase from approximately 97.6% to approximately 98.8%.

Contribution requirements for the Fiscal Year ending June 30, 2026 were set based on the asset values as of June 30, 2025. 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 23, 2025, the estimated contribution for Fiscal Year 2025-26 required to fund the benefit allocated to the Normal Cost, as a percentage of payroll, was 11.29% for Tier 2 (as compared to 21.07% for Tier 1). As of the July 1, 2025 actuarial valuation report, 62% 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 (11) 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 (11)(d), the Power System paid Healthcare Benefits of approximately $87.2 million in Fiscal Year 2024-25 (as part of a total Department contribution of approximately $126.8 million), and the Power System paid Healthcare Benefits of approximately $72.2 million in Fiscal Year 2023-24 (as part of a total Department contribution of approximately $110.3 million). For the Fiscal Year ended June 30, 2025, the Department budgeted approximately $86.9 million to be paid from the Power Revenue Fund for Healthcare Benefits (with the total Department paying approximately $131.7 million). For the Fiscal Year ending June 30, 2026, the Department has budgeted approximately $96.2 million to be paid from the Power Revenue Fund for Healthcare Benefits (with the total Department paying approximately $145.8 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, 2025, as of June 30, 2025, the market value of the assets of the Healthcare Benefits was approximately $3.6 billion, which would result in an unfunded actuarial accrued liability (based on the market value of assets) of approximately $322.7 million; the actuarial value of the assets in the Healthcare Benefits as of such date was approximately $3.5 billion, which would result in an unfunded actuarial accrued liability (based on the actuarial value of assets) of approximately $435.3 million. As of June 30, 2025, the Healthcare Benefits had unrecognized investment gains of approximately $112.7 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, 2025, the ratio of the actuarial value of assets to actuarial accrued liabilities decreased from 100.90% as of June 30, 2024 to 88.96% as of June 30, 2025. On a market value of assets basis, the funded ratio decreased from 102.38% as of June 30, 2024 to 91.81% as of June 30, 2025. The unfunded actuarial accrued liability measured using the actuarial value of assets increased from $(28.8) million (a surplus of assets over liability) to $435.3 million as of June 30, 2025.

According to the actuarial valuation and review of the Healthcare Benefits, which was completed by The Segal Company on October 31, 2024, as of June 30, 2024, 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 $76.1 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 $28.8 million. As of June 30, 2024, the Healthcare Benefits had unrecognized investment gains of approximately $47.3 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, 2024, the ratio of the actuarial value of assets to actuarial accrued liabilities decreased from 114.16% as of June 30, 2023 to 100.90% as of June 30, 2024. On a market value of assets basis, the funded ratio decreased from 113.17% as of June 30, 2023 to 102.38% as of June 30, 2024. The unfunded actuarial accrued liability (on an actuarial value of assets basis) decreased from a surplus of $371.7 million as of June 30, 2023 to a surplus of $28.8 million as of June 30, 2024.

Contribution requirements for the Fiscal Year ending June 30, 2026 were set based on the asset values as of June 30, 2025. 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, 2025, for Fiscal Year 2025-26, the Normal Cost, as a percentage of payroll, was estimated to be 6.85% for Tier 2 (as compared to 5.81% 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. As of June 30, 2025, the Power System had a net OPEB liability surplus of $19.1 million comprised of $52.4 million surplus of retiree medical and $71.5 million liability in death benefits. As of June 30, 2024, the Power System had a net OPEB liability surplus of $160.2 million comprised of $233.7 million surplus of retiree medical and $73.5 million liability in death benefits. For more information about the Department's OPEB liabilities as reported in accordance with GASB No. 75, see Note (11) and "Required Supplementary Information" of the Department's Power System Financial Statements.

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 most recently approved transfers totaling $225,782,000 to the City during the Fiscal Year ending June 30, 2026.

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, 2021 – 2025
($ in thousands)

Fiscal Year Ended June 30	Amount of Power Transfer
2021	$218,355
2022	225,015
2023	232,043
2024	244,695
2025	219,312

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 currently consists of a combination of commercial insurance policies, a Wildfire Self-Insurance Trust Fund, 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 $40 million, which includes 50% of co-insurance for the 2025-26 policy year (April 2025 to April 2026). 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 $40 million are additional layers of commercial liability insurance that provide an additional $120 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 $106.25 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 $121.50 million of commercial wildfire insurance, totaling an insurance tower of $227.75 million. The Department augments and supports its wildfire coverage with a Wildfire Self-Insurance Trust Fund. The Wildfire Self-Insurance Trust Fund was established in December 2024 to assist in the settlement of wildfire claims, and as of June 30, 2025, the Wildfire Self-Insurance Trust Fund had a balance of $46.24 million. Through the utilization of commercial insurance, the Wildfire Self-Insurance Trust Fund and additional self-insurance, the wildfire insurance program currently has a total limit of $273.99 million available for wildfire losses.

To further complement its overall wildfire insurance program, the Department has provided for $100 million of wildfire coverage through a CAT Bond. The $100 million wildfire index CAT Bond is for the three-year period from August 2025 to September 2028. Unlike parametric and indemnity wildfire CAT Bonds, the wildfire index CAT Bond is triggered by attachment to the amount of losses of certain covered California counties. The wildfire index CAT Bond is intended to supplement the Department's self-insurance retention and wildfire risk management program. 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.

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*."

In addition to the excess general liability insurance programs, the Department continues to maintain a bona fide program of self-insurance as well. As of June 30, 2025, the portion of the Power Revenue Fund set aside for self-insurance had a balance of approximately $242.5 million in a restricted cash account. The Power Revenue self-insurance fund is specific to the Power System and is primarily designed to cover a large catastrophic event that could affect the Power System 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 are not included in the City's investment pool program. The Department manages the investment of the Trust Funds in which approximately $787.3 million (investments at fair market value) was on deposit as of June 30, 2025. 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 June 30, 2025, the debt reduction trust fund had a balance of approximately $543.9 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 JUNE 30, 2025
(DOLLARS IN THOUSANDS)
(UNAUDITED)

	Fair Market Value
U. S. Sponsored Agency Issues	$558,009
Medium term corporate notes	128,262
Money market funds	32,341
Municipal obligations	23,599
Other state bonds	17,746
U. S. Government Securities	9,360
California state bonds	7,111
Supranationals	5,953
Commercial paper	4,944
Total	$787,324

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 June 30, 2025, the Power System had approximately \$1.09 billion of unrestricted cash and approximately \$1.59 billion of restricted cash on deposit with the City. For information regarding the fair market value adjustment of the Department's pooled investment fund assets as of June 30, 2025, see Note (7)(b) of 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, 16% of the pool, as of June 30, 2025, had maturities less than one month and 39% of the pool, as of June 30, 2025, had maturities of one year or less.

The following table describes the investments held in the City's Pooled Investment Fund (which includes amounts held in the City's General Investment Pool and the City's Special Investment Pool) as of June 30, 2025.

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CITY OF LOS ANGELES POOLED INVESTMENT FUND
ASSETS AS OF JUNE 30, 2025
(Dollars in Thousands)
(Unaudited)

	Amount[1]	Percent of Total[1]	Power System Share[1][2]
U.S. Treasury Notes	$ 10,149,336	61.74%	$ 1,657,481
Medium-Term Notes	1,883,039	11.46	307,657
U.S. Agencies Securities	1,296,087	7.89	211,816
Commercial Paper	2,575,007	15.66	420,411
Short-Term Investment Funds	249,886	1.52	40,806
Asset-Backed Securities	48,310	0.29	7,785
Supranationals	179,570	1.09	29,262
Securities Lending Short-Term Repurchase Agreement	57,886	0.35	9,396
Total General and Special Pools[3]	**$16,439,121**	**100.00%**	**$2,684,614**

Source: Department of Water and Power of the City of Los Angeles and Los Angeles City Treasurer.
(1) Fair Market Value as of June 30, 2025.
(2) Department funds held by the City are both unrestricted and restricted funds.
(3) Totals may not equal sum of parts due to rounding.

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 as of June 30, 2025 and 2024, see Note (7) of the Department's Power System Financial Statements.

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 otherwise 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.

Interim Rate Review. The last rate action covered a five-year period from Fiscal Year 2015-16 through Fiscal Year 2019-20. In 2019, the Department and the Office of Public Accountability (the "OPA") each conducted their ordinance-mandated independent interim rate review. As part of this review, on the recommendation of 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. In June 2025, the Board approved an increase of the Base Rate revenue target for Fiscal Year 2025-26 of 0.58% 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 described below under "ELECTRIC RATES – Board Adopted Financial Planning Criteria." 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 start a water rate review in calendar year 2025, but is still reviewing the need and proposed schedule for the next power rate action with the Chief Executive Officer. Department staff expects the power rate action to start after the completion of the water rate action.

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 such 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 May 27, 2025, Tim O'Connor was appointed as the new Executive Director of the OPA (the "Ratepayer Advocate") for a five-year term. The electric rate action effective April 15, 2016 was supported by the then-Ratepayer Advocate following his review of the proposed rate changes. The rate action included certain changes proposed by such 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 was increased to 2.0% of Power System sales beginning in Fiscal Year 2020-21. Since that time, a new accrual approach has been adopted for the allowance for doubtful accounts, which uses a three-year write-off average rate of Power System sales, starting in Fiscal Year 2023-24 (0.5%). As of June 30, 2025, the Power System's allowance for doubtful accounts was $394.0 million and accounts receivable were $1.52 billion (including utility user's tax). Of these amounts, $903.4 million (59.51% of total receivables) were 120 days or more past the payment due date. As of June 30, 2024, the Power System's allowance for doubtful accounts was $312.5 million and accounts receivable were $1.27 billion (including utility user's tax). Of these amounts, $758.0 million (59.50% 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 began to resume service disconnections for certain residential customers in June 2024). 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 was 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 11,525 megawatts ("MW") and net dependable capacity (or average expected capacity in the case of renewable resources) of 7,918 MW as of September 30, 2025, and properties with a net book value of approximately $15.9 billion as of June 30, 2025. The Power System's highest load registered 6,502 MW on August 31, 2017. Based on the Department's December 2024 Retail Electric Sales and Demand Forecast, the Department anticipates that gross customer electricity consumption will increase from Fiscal Year 2022-23 to Fiscal Year 2032-33 at a forecasted rate of approximately 1.53% 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% cumulative energy savings from 2010 through 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 September 30, 2025), and energy mix (actual numbers for calendar year 2024 as reflected in the Department's most recent Annual Power Content Label), were approximately as follows:

DEPARTMENT GENERATION MIX PERCENTAGES

Resource Type	Capacity Percentage[(1)]	Energy Percentage[(2)]
Natural Gas	34.3%	30%
Large Hydro	15.3	3
Coal	10.4	11
Nuclear	3.4	15
Renewables	35.0	41
Storage	2.6	–
Unspecified Sources of Energy[(3)]	–	–
Total	100.0%	100.0%

(1) Net Maximum Unit Capability as of September 30, 2025.
(2) Energy percentage is based on the Department's calendar year 2024 fuel mix submission as part of the 2024 Annual Power Content Label to the California Energy Commission. The Power Content Label does not reflect compliance with the Renewables Portfolio Standard (RPS), which measures the use of tracking instruments called Renewable Energy Credits (RECs) over the course of multi-year compliance reports.
(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 June 30, 2025.

Department-Owned Generating Units

The Department's solely owned generating facilities, as of September 30, 2025, are summarized in the following table:

DEPARTMENT OWNED FACILITIES

Type of Fuel	Number of Facilities	Number of Units	Net Maximum Plant Capacity (MW)(1)	Net Dependable or Average Expected Plant Capacity (MW)(1)(4)
Natural Gas	4(2)	29(2)	3,377	3,182
Large Hydro	1	7	1,265	1,265
Renewables	65	162(3)	362	86(4)
Storage	1	1	20(5)	–(5)
Subtotal	**71**	**199**	**5,024**	**4,533**
Less: Payable to the California Department of Water Resources	–	–	(120)(6)	(28)(6)
Total	**71**	**199**	**4,904**	**4,505**

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

(1) Net dependable capacity is based on 2024-25 capacity ratings; for renewables, figure represents average expected capacity. See footnote 4.

(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 historical generation, in addition to statistical modeling of likely output without consideration of weather conditions that may affect the ability of certain renewable resources to reach its average expected capacity.

(5) Storage consists of a 10 MWh battery which can discharge up to 20 MW for 30 minutes. Storage capacity contributes to the Net Dependable or Average Expected Plant Capacity of the Power System but such contribution is not included in the calculation methodology as currently utilized for the purposes of this table.

(6) 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.

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

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 3,377 MW and a combined net dependable generating capacity of 3,182 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 1,503 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 525 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. 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. The final number of individual plaintiffs is approximately 1,300 following the dismissal of plaintiffs who did not participate in discovery. All pending cases have been deemed related by the court and are assigned to the same judge in the Los Angeles Superior Court.

The Department and the plaintiffs have agreed to settle this litigation for $59.89 million after mediation. The fact that the parties have agreed to settle the litigation has been publicized by various news outlets. The parties have drafted a proposed written settlement agreement that will be submitted to the Department for approval.

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 432 MW with a net dependable capacity of 423 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 776 MW and a net dependable capacity of 731 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 1,492 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 average expected capacity of Owens Gorge and Owens Valley Hydroelectric Generation totals 34 MW and the net maximum plant 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 Hydroelectric Generation. 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 average expected capacity of these smaller units is 27 MW and the net maximum plant 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 September 30, 2025, 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 or Average Expected Capacity (MW)
Coal	1	1,202[(1)]	1,164
Natural Gas	1	578[(2)]	483
Large Hydro	1	496[(3)]	270[(3)]
Nuclear	1	387[(4)]	380
Renewables/Distributed Generation	94,384[(5)]	3,678	1,116[(6)]
Storage	2	281[(7)]	–[(7)]
Total	**94,390**	**6,622**	**3,413**

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

(1) The Department's IPP entitlement is 48.62% of the net maximum 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. As discussed below, the repowering of IPP to replace the coal units with combined cycle natural gas units with a net maximum plant capacity of 840 MW is expected to be completed by December 2025.

(2) The Department's Apex Generating Station entitlement is 100% of the power produced.

(3) 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.

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

(5) 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.

(6) For renewables, figure represents average expected capacity. Figure based on historical generation, in addition to statistical modeling of likely output without consideration of weather conditions that may affect the ability of certain renewable resources to reach its average expected capacity.

(7) Storage capacity contributes to the Net Dependable or Average Expected Plant Capacity of the Power System but such contribution is not included in the calculation methodology as currently utilized for the purposes of this table.

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

***Intermountain Power Project*.**

General. The IPP, which is located near Delta, in Millard County, Utah, was originally constructed as a coal-fired, steam electric generating plant with a net rating of 1,800 MW. 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, administering, operating and maintaining the IPP. In Fiscal Year 2024-25, the IPP operated at a plant net capacity factor of 43.59% and provided approximately 6.87 million megawatt-hours ("MWhs") of energy to its power purchasers, which includes approximately 4.30 million MWhs to the Power System.

In December 2025, a repowering of the generating station to replace the coal units with combined cycle natural gas units as the source of generation for the IPP is expected to be completed. See "– *Intermountain Generating Station upon the termination of the IPP Contract*" below for a further discussion of the repowering of the IPP generating station and the development of the repowering project.

Following completion of such repowering, the IPP consists of: (i) a two-unit, combined-cycle natural gas-fired electric generating plant, consisting of two power blocks, each with one gas turbine, a heat recovery steam generator train and a single steam turbine, with an approximate combined net generation capability of 840 MW (the "Intermountain Generating Station") and a switchyard (the "Switchyard"), located near Lynndyl, 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) certain water rights (which water rights, together with the Intermountain Generating Station and the Switchyard, are referred to herein collectively as the "Generation Station"); and (vi) coal generating units and related facilities which are not in operation. As a result of the repowering, coal supplies to fuel the generating plant are no longer needed and the railcar service center constructed as part of the original IPP project to provide delivery of coal supplies ceased operating in August 2025.

Power Contracts. Pursuant to a Power Sales Contract with IPA (the "IPP Contract"), the Department is currently entitled to 48.617% of the capacity of the IPP. The Department's capacity entitlement under the IPP Contract is currently equal to approximately 408 MW. The term of the IPP Contract ends on June 15, 2027. Upon the termination of the existing IPP Contract, the Department's entitlement share of the capacity of the IPP will increase. See "– *Intermountain Generating Station upon the termination of the IPP Contract*" below. 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. The Department's capacity entitlement under the IPP Excess Power Sales Agreement is currently equal to approximately 152.6 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."

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, IPA and the Department entered into 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. As noted above, new generation facilities entered service in October 2025 and planned operation is expected to occur in December 2025 (after the originally scheduled date of July 1, 2025). The estimated cost of the repowering of the plant to the new combined cycle units at IPP was approximately $1.7 billion. This estimate does not include the hydrogen facilities being constructed as described below.

IPA executed a contract in early 2022 securing energy conversion and storage services 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. Upgrades to the Switchyard and replacement of converter stations are also being undertaken at an estimated cost of approximately $2.8 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 (the "IPP Agreement for Sale of Renewal Excess Power") 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 will govern the sale of IPP capacity and output beginning 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.

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 the IPP (currently equal to approximately 152.6 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 have recalled 0.22% of the capacity of the IPP (equivalent to 2 MW) from the Department for the winter season which started September 2025 and will end March 2026. The percentage of the capacity of the IPP subject to recall will increase to 21.057% (equal to 177 MW) in 2027 upon the effectiveness of the IPP Agreement for Sale of Renewal Excess Power which will take effect on the same day as the IPP Renewal Power Sales Contract described above. The Department can give no assurance that the capacity of the IPP subject to recall from the Department under the IPP Excess Power Sales Agreement or the IPP Agreement for Sale of Renewal Excess Power will not be recalled in the future in accordance with the agreement terms.

Fuel Supply. In March 2024, IPA executed a Fuel and Asset Management Agreement (the "FAMA") with Tenaska Marketing Venture ("TMV") to purchase natural gas for use at the IPP. As fuel manager, TMV offers purchasing rights for natural gas and guarantees delivery to the IPP, providing reliable supply during high market volatility. Under the FAMA, TMV is also responsible for nominating, scheduling, and delivering natural gas to the IPP. TMV has been providing 100% of the gas to the IPP as of October 2024 to support commissioning activities.

For more information on the effect of certain environmental considerations on the 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, 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 had 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; Southern California Edison Company ("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 2024 annual funding status report which is based on a 2023 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 72% funded and that its share of decommissioning costs through SCPPA was 82% funded. The Department's direct share of costs is $228.3 million and SCPPA's share is $238.9 million, of which the Department's portion is $160.1 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 – 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 June 30, 2025, 152 casks, each containing 24 spent fuel assemblies, and 30 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.

Decommissioning has been completed and the land was returned to the Navajo Nation in March 2024; however, the Department retains responsibility for its share of environmental monitoring and remediation 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 – *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 14% of the Department's energy in each of 2023 and 2024, or about one-third of the renewable energy, which comprised 40% and 41% of the total energy mix in 2023 and 2024, respectively, as reflected in the Department's Annual Power Content Label for such years. The Power Content Label does not reflect compliance with the RPS, which measures the use of tracking instruments called Renewable Energy Credits (RECs) over the course of multi-year compliance reports.

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, Wyoming, and New Mexico. Such power purchase agreements provide for an aggregate of 1,220 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."

SW Wyoming Wind Project. The SW Wyoming Wind Project is a power purchase agreement between the Department and Avangrid Power, LLC, for renewable wind energy from the Pleasant Valley Wind Energy

Center located in Wyoming. The project consists of 80 wind turbines with a total installed capacity of 144 MW, and began commercial operation in 2003. The Department has secured 82.7 MW (57.45%) of the project's output, including associated environmental attributes. The Department is expected to receive approximately 233,00 MWh annually from the project. The current agreement covers the delivery of renewable energy and associated environmental attributes through December 2026. Energy is delivered to the Department at Mona Sub-Airway Switchyard and scheduled in accordance with Western Electricity Coordinating Council ("WECC") protocols.

Pebble Springs Wind Project. The Pebble Springs Wind Project is a 99 MW wind energy facility located in Gilliam County, Oregon. The project was developed by Pebble Springs Wind, LLC, a subsidiary of PPM Energy (now Avangrid Renewables), and began commercial operation in 2009. The Department has secured a 68.7 MW (69.6%) share of the project's output under a power sales agreement with SCPPA. The project is expected to produce approximately 275,000 MWh annually, of which the Department is expected to receive approximately 193,000 MWh until February 2027. Energy is delivered to the Department via the Pacific DC Intertie and received at the Sylmar Converter Station.

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 eleven 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.

Large Scale Solar Energy. The Department has entered into the following 14 power purchase agreements ("PPAs") for the purchase of renewable energy from 1,727 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 was developed by Arevon Energy, Inc. 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. This facility began full commercial operation in November 2024.

- 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 was developed by Arevon Energy, Inc. 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. This facility began full commercial operation in July 2025.

- 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 246.9 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.

- The fourteenth PPA with an option to purchase is a 30-year contract through SCPPA for 235 MW of the Milford Solar Phase II project, which is adjacent to the Milford Wind Phase I and Milford Wind Phase II project and is being developed by Longroad Energy LLC. Milford Solar Phase II is expected to deliver an average of approximately 585,000 MWhs of renewable energy a year to the Department. The facility is expected to begin full commercial operation by the end of December 2026.

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*."

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 Department has executed an amendment to the power sales agreement with SCPPA to extend energy deliveries from the Heber-1 Project for an additional 25-year term from February 2, 2026 to February 1, 2051. 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 generating capacity from the Heber-1 Project is expected to be 52 MW. The Department's share is 78.0% (40.56 MW) for the remaining term. The equivalent average energy delivered to the Department is expected to be 338 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 165.65 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.

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 115.8 MW comprised of 4 MW of solar photovoltaic generation in the Owens Valley and 4 MW of renewable landfill gas generation, and 107.8 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; (vii) the FiT Plus program, which facilitates the installation of energy storage with existing and new FiT photovoltaic projects; and (viii) the Self Generation Incentive Program ("SGIP"), which the Department has been authorized by the CPUC to administer for its service territory, and which initially includes approximately $36.0 million in funding for deploying solar and energy storage in low-income households. In total, approximately 719 MW of customer-owned net energy metered photovoltaic solar projects have been installed in the Department's in-basin service territory as of September 2025.

Certain of these programs are further described below:

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 26.19 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 7.19 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'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 35 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.

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 for a five-year term from the Roseburg SB 859 biomass project, which began making deliveries of energy in February 2021. 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 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 20 MW Beacon utility-scale BESS project, located on the Beacon Property, which commenced operation in October 2018.

- 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 solar and energy storage systems at the Eland Solar & Storage Center, Phase 1 and the Eland Solar & Storage Center, Phase 2. Phase 1 was commissioned in November 2024, and Phase 2 was commissioned on July 31, 2025. The energy storage at the Eland Solar & Storage Center, Phase 1 is a 131.25 MW/4-hour Tesla Li-ion Battery System. The energy storage at the Eland Solar & Storage Center, Phase 2 is a 150 MW/4-hour Tesla Li-ion Battery System.

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

The Department is pursuing the development of a project selected through a proposal submitted under a SCPPA Standalone Energy Storage RFP, encompassing various technologies. The proposed project would deploy a Long Duration Energy Storage (LDES) near a major renewable generation hub, with commissioning targeted for the first quarter of 2029.

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. As of December 2024, there were slightly more than 8,700 Department customers subscribed to the Green Power Program.

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 would 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.

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 and to use the LA100 Study as a guide to fulfill the energy vision being pursued by the federal Administration at that time, 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 repowering 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 proposed project (the "Scattergood Green Hydrogen-Ready Modernization Project") is aimed 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 and Harbor Unit 5 from once-through cooling to closed-cycle wet cooling in compliance with the California State Water Resources Control Board mandate to cease the use of coastal and estuarine waters for power plant cooling by December 31, 2029.

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 sought federal funding through the federal Department of Energy's ("DOE") Regional Clean Hydrogen Hubs ("H2Hub") program which provided for funding to establish no more than 10 regional hydrogen hubs across the country.

On May 19, 2022, the City Council directed the Department and the Port of Los Angeles ("POLA") to coordinate a local effort to create and submit a proposal to the DOE proposing the Greater Los Angeles area for consideration as a regional "green" hydrogen hub. Subsequently, to support a unified statewide approach, the Department contributed to an application led by ARCHES. This application, submitted by ARCHES and its partners, outlined a proposed "renewable" and "clean" hydrogen ecosystem in California, incorporating new and existing projects.

On October 13, 2023, the prior federal Administration announced $7 billion in awards for seven regional hydrogen hubs, of which the California-centered hub was selected for an award of up to $1.2 billion. ARCHES selected the Scattergood Generating Station Units 1 and 2 Green Hydrogen-Ready Modernization Project as a subrecipient of up to $100 million in federal funds. The subrecipient agreement between ARCHES and the Department was approved by the Board on December 10, 2024. Since then, the Department has continued to collaborate with ARCHES, providing the required deliverables and cost reporting for the Scattergood project under the H2Hub program.

On October 1, 2025, the DOE announced the termination of federal funding in connection with 321 financial awards supporting 223 projects. In its announcement, the DOE stated that the termination of funding was based upon its determination that the affected projects did not adequately advance the nation's energy needs, were not economically viable, and would not provide a positive return on investment of taxpayer dollars. This broad funding rescission included the cancellation of the DOE's commitment to provide up to $1.2 billion for the ARCHES H2Hub. ARCHES submitted a formal letter to the DOE on October 11, 2025, appealing the funding termination. The Department cannot predict the outcome of ARCHES' pending appeal of the federal funding termination. It is the Department's view that the potential loss of anticipated federal funding does not diminish the Department's assessment of the underlying need for the Scattergood project, the necessity of which was determined independently of federal funding, and that the Scattergood project remains a critical component of the Department's clean energy transition.

The State of California has reaffirmed its support for ARCHES, as reflected in public statements by Governor Gavin Newsom and U.S. Senator Alex Padilla. The Department has continued to pursue regional collaboration with potential industry partners, engagement with regulatory agencies and broad stakeholder groups, and community outreach to support the practical development and deployment of green hydrogen infrastructure. The Department will also continue to monitor legal and regulatory developments at the federal, state, and local levels, including those related to the H2Hub program.

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. This total cost in net present value represents both fixed capital and variable operating and maintenance costs of the Power System and is primarily used as a metric to compare cases. 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 did not include potential cost savings from other potential sources of funding such as the federal Inflation Reduction Act of 2022 (the "IRA"), the federal Infrastructure Investment and Jobs Act of 2021, and state and federal grants. The extent of the availability, if any, of any federal funding sources will be determined by the current federal Administration. See "FACTORS AFFECTING THE DEPARTMENT AND THE ELECTRIC UTILITY INDUSTRY – Changing Laws, Energy Policies and Requirements."

The next iteration of the Department's Strategic Long-Term Resource Plan is being finalized and has been renamed the LA100 Plan. The LA100 Plan focuses on only one case along with a number of sensitivities to evaluate risk, and provides an update to the 2022 Strategic Long-Term Resource Plan. The LA100 Plan will include analysis of rate drivers and additional clean energy opportunities to refine and optimize costs over the long-term. The LA100 Plan will reflect an update of the net present value of the estimated total bulk portfolio cost through 2045, including both fixed capital and variable operating and maintenance costs of the Power System, to support a recommended resource plan for achieving the Department's goal of 100% carbon-free energy by 2035, based on the updated LA100 Plan methodologies and cost estimates. The LA100 Plan is anticipated to be completed by December 31, 2025. The LA100 Plan is intended to serve as a conceptual framework rather than a definitive, prescriptive roadmap. Following its completion, it is expected that the LA100 Plan will continue to evolve and the Department's long-term strategies are anticipated to continue to be adjusted and further refined in response to, among other things, new data, policy developments, stakeholder input, and advances in technology.

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% cumulative energy savings from 2010 through 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 started offering electrification incentives for all electric commercial cooking equipment and appliances.

Custom Performance Program/Business Offerings for Sustainable Solutions. As initially established, the Custom Performance Program (the "CPP") provided 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, retro-commissioning, chiller efficiency, and/or other innovative energy savings strategies.

Beginning July 1, 2024, the CPP was rebranded as the Business Offerings for Sustainable Solutions ("BOSS") Program. The BOSS Program continues to fast-track smaller, less energy-intensive projects through its "Custom Express" service, which offers energy savings projections to expedite application processing and faster payments to customers. Additionally, the Custom Calculated service provides in-depth analyses to custom calculate the energy savings of individual efficiency projects. Since 2007, the CPP/BOSS Program has achieved over 624 GWhs of energy savings and introduced electrification incentives for space and 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 better meet their lighting needs, attain greater energy savings, and receive higher incentives. Commercial lighting programs have achieved over 851 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 over 528 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 initiative targeting customers who qualify under the Department's Low-Income or Senior Citizen/Disability Lifeline Rates, as well as multi-residential and non-profit customers. The program has expanded to include multi-family and mobile home communities, civic, community, faith-based organizations, and educational institutions. Currently, the REP is suspended while the program seeks a new third-party contractor to administer the program and provide energy-efficient refrigerators for this customer segment to replace older, inefficient, but operational models. Since 2007, REP has achieved over 106 GWhs of energy savings.

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.

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 that are not included in the 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 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.

As the Department ramps up its technology assessment efforts in the Emerging Technologies program, it has partnered with the NREL to develop a technology prioritization tool. The tool prioritizes 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 for 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 September 2025, the Department has spent approximately $1.9 billion on its energy efficiency programs, and these programs are estimated to have reduced long-term peak period demand and consumption by approximately 997 MW and resulted in approximately 6,166 GWhs of energy savings. Through the energy-efficiency rebate and incentive programs, residential and commercial customers saved approximately 360 GWh incrementally for Fiscal Year 2024-25, falling short of energy savings targets by 47 GWh. The Department spent approximately $98 million on energy efficiency programs for Fiscal Year 2024-25 of its approximately projected $202 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 better manage their use of electricity. 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 43.9 billion equivalent cubic feet of natural gas during Fiscal Year 2024-25. In addition, the Department's fossil fuel requirements for the Apex Power Project were 7.9 billion equivalent cubic feet of natural gas during Fiscal Year 2024-25. 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 2.88% of the Department's average daily natural gas requirements for Fiscal Year 2024-25. 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 June 30, 2025, the Department had entered into financial natural gas hedges in various notional amounts per Fiscal Year for each Fiscal Year through Fiscal Year 2029-30 with an aggregate notional amount of approximately 73.6 million MMBtu. These financial hedges cover up to approximately 49.0% of the Department's natural gas requirements based on the latest budget for the Fiscal Years through 2030-31. Tables describing the notional amount for specified Fiscal Years and the durations of the hedges, as well as a discussion of the credit, basis and termination risks associated with the Department's financial natural gas hedges as of June 30, 2025 and 2024, 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 June 30, 2025, approximately 49% and 37% of the Department's projected natural gas needs have been hedged for Fiscal Year 2025-26 and Fiscal Year 2026-27, respectively, through financial natural gas hedges and gas reserves. This ratio declines such that by Fiscal Year 2030-31, approximately 10% 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. 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 the prior year's natural gas price spikes and that removal of the Commission's storage level limitation would provide a significant tool to mitigate future gas price spikes. 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. In December 2024, the CPUC approved a proposed decision to create a process to reassess the need for the Aliso Canyon gas storage facility as demand for natural gas declines. The decision establishes a specific natural gas peak demand target, which is the level at which it determined Southern California peak demand can be served without Aliso Canyon. Beginning in June 2025, the CPUC will issue biennial assessments with a recommendation of the appropriate Aliso Canyon inventory based on natural gas demand reduction levels and reliability and economic analyses. When the forecasted peak day demand for two years out decreases to the target level, and an assessment shows that Aliso Canyon could be closed without jeopardizing reliability or just and reasonable rates, the CPUC will open a proceeding to review the assessment's conclusions and address any relevant issues related to permanent closure and decommissioning of the gas storage facility.

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 365 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 approximately 4% 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 access 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. In December 2024, the Board approved an implementation agreement for the Department's future participation in the Cal ISO's Extended Day-Ahead Market ("EDAM"). EDAM is a voluntary, wholesale energy market designed to optimize the availability of energy on existing transmission line infrastructure in the Western United States. Cal ISO's EDAM is expected to launch in 2026. Through participation in EDAM, the Department and other utilities will be provided with a preview of anticipated surplus energy days in advance, which is expected to help mitigate renewable energy curtailments and GHG emissions. It is anticipated that the Department will officially enter the EDAM market in mid-2027. AB 825, signed into law in September 2025, authorizes the Western EIM and EDAM to be governed by a new, independent regional organization (rather than Cal ISO) in the future if specified requirements are satisfied. The creation of a new regional governance structure is expected to facilitate the regionalization of these energy markets among the Western states.

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 $2.8 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 entered into 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 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. 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. Under the IPP Agreement for Sale of Renewal Excess Power, which will take effect in June 2027, the Department will be provided with firm transmission rights to approximately 50% of the total capacity on each of the sections of the NTS. The Department can have up to a maximum NTS share allocation of 100% of the total NTS capacity depending on the generation deemed excess by the Utah municipalities and cooperatives that have access to such power post-2027. See "– Jointly-Owned Generating Units and Contracted Capacity Rights in Generating Units – *Intermountain Power Project*."

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 Board approved the Fiscal Year 2025-26 capital improvement program on May 13, 2025. A forecast of Power System capital improvement program expenditures for Fiscal Year 2025-26 through Fiscal Year 2029-30 was developed by the Department in conjunction with the preparation of the Power System budget for Fiscal Year 2025-26.

The detailed plans for and costs of projects to be undertaken in connection with the re-building of areas affected by the Palisades Fire are being developed. The forecasted Power System capital improvement program for Fiscal Year 2025-26 through Fiscal Year 2029-30 reflects certain preliminary estimates of anticipated expenditures associated with the re-building over the five-year period. However, these estimates are preliminary and are expected to change as the plans are further developed and the recovery efforts continue.

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 2024 Retail Electric Sales and Demand Forecast, the Department anticipates that gross customer electricity consumption will increase from Fiscal Year 2022-23 to Fiscal Year 2032-33 at a forecasted rate of approximately 1.53% 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% cumulative energy efficiency savings from 2010 through 2020 and is now focused on an additional 3,434 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 2025-26 through Fiscal Year 2029-30, the Department expects to invest approximately $18.5 billion in capital improvements to the Power System.

EXPECTED CAPITAL IMPROVEMENTS TO THE POWER SYSTEM
FIVE-YEAR PERIOD BEGINNING JULY 1, 2025
(in Millions)

	5-Year Totals
Infrastructure: Various Generation Station Improvements	$ 3,593
Energy Efficiency	1,060
Power System Reliability Program	7,861
Renewable Portfolio Standard (RPS): Wind Projects, Renewable Energy Project Development, Renewable Transmission Projects, RPS Storage	3,431
Power System Resource Plan	10
Shared Services: Facilities, Customer Services, Fleet	2,556
Total Power System Capital Improvements	$18,512

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

The table below indicates, for Fiscal Year 2025-26 through Fiscal Year 2029-30, 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)]
2026	$812	$1,820	$2,632
2027	1,312	2,297	3,609
2028	1,582	2,649	4,231
2029	1,606	2,718	4,324
2030	1,259	2,455	3,715
	$6,572	$11,940	$18,512

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) higher than anticipated construction bids or costs, including as a result of tariffs, (vi) material and/or labor shortages, (vii) unforeseen site and subsurface conditions, (viii) adverse weather conditions or natural disasters, (ix) contractor defaults, (x) labor disputes, (xi) unanticipated levels of inflation, (xii) environmental issues, (xiii) the ability to access the capital markets at particular times and (xiv) 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 5,221 customers are served. As of June 30, 2025, 32% of the Power System's total energy sales (measured in MWhs) were to residential customers, 61% to commercial and industrial customers and the remaining 7% to all other purchasers. Revenues from residential customers, commercial/industrial customers, and other customers were approximately 36%, 62%, and 2% 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)

	Fiscal Year Ended June 30				
Operating Statistics	**2025**	**2024**	**2023**	**2022**	**2021**
Net Energy Load[1]	23,530	22,994	23,859	23,997	23,797
Net Hourly Peak Demand (MW)	6,251	5,453	6,216	4,911	6,106
Annual Load Factor (%)	42.97	48.00	43.81	55.79	44.49
Electric Energy Generation, Purchases and Interchanges[1]					
Generation[2][3]	15,699	16,384	17,172	17,194	17,281
Purchases[3]	9,998	8,876	9,148	9,440	8,988
Miscellaneous Energy Receipts[1]	--	96	–	–	705
Total Energy[1]	25,696	25,356	26,320	26,634	26,974
Less:					
Miscellaneous Energy Deliveries[1][4]	--	--	426	511	–
Losses and System Uses[1]	2,723	2,833	2,386	2,595	4,479
On-System Sales[1]	22,974	22,523	23,508	23,528	22,495
Sales of Energy[1]					
Residential	7,351	7,077	7,736	7,383	7,707
Commercial and Industrial	13,879	13,954	13,959	14,092	13,220
All Other	1,533	1,026	1,722	1,891	2,087
Total	22,763	22,057	23,417	23,366	23,014
Number of Customers – (Average, in thousands):					
Residential	1,458	1,453	1,440	1,430	1,414
Commercial and Industrial	128	128	128	128	126
All Other	7	7	7	7	7
Total	1,593	1,588	1,575	1,565	1,547

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

(1) Thousands of MWhs.
(2) 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.
(3) Purchases from SCPPA are classified as Generation for quarterly results and Purchases for Fiscal Year end results.
(4) 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)

	Fiscal Year Ended June 30[1]				
	2025	**2024**	**2023**	**2022**	**2021**
Operating Revenues					
Residential	$1,887,767	$1,679,399	$1,717,646	$1,637,120	$1,614,033
Commercial and Industrial	3,290,202	3,036,936	2,857,601	2,784,691	2,492,138
Sales for resale[2]	159,162	118,193	326,347	230,160	186,706
Other[3]	(28,831)	(9,160)	56,945	(58,211)	(24,399)
Total Operating Revenues	$5,308,300	$4,825,368	$4,958,539	$4,593,760	$4,268,478
Average Revenue per kWh Sold[4]					
Residential	0.257	0.237	0.222	0.222	0.209
Commercial and Industrial	0.237	0.218	0.205	0.198	0.189
Average Annual Residential Usage[5]	5	5	5	5	5
Operating income	$1,080,254	$ 771,963	$ 742,176	$ 800,988	$ 744,139
As % of revenues	20.4%	16.0%	15.0%	17.4%	17.4%
Adjusted Change in Net Position, excluding Power Transfer and including accounting change[6]	$1,072,109	$ 829,356	$ 833,815	$ 532,290	$ 633,942
Adjusted Change in Net Position, including Power Transfer and accounting change[6]	$ 852,797	$ 584,661	$ 601,772	$ 307,275	$ 415,587

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) Includes sales of power and transmission services to other utilities.
(3) Net of Uncollectible Accounts.
(4) 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.
(5) MWh use per residential customer.
(6) "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)

	Fiscal Year Ended June 30(1)				
	2025	**2024**	**2023**	**2022**	**2021**
Operating Revenues					
Sales of Electric Energy:					
Residential	$1,887,767	$1,679,399	$1,717,646	$1,637,120	$1,614,033
Commercial and industrial	3,290,202	3,036,936	2,857,601	2,784,691	2,492,138
Sales for resale	159,162	118,193	326,347	230,160	186,706
Other(2)	(28,831)	(9,160)	56,945	(58,211)	(24,399)
Total Operating Revenues	$5,308,300	$4,825,368	$4,958,539	$4,593,760	$4,268,478
Operating Expenses					
Production:					
Fuel for Generation	$ 295,893	$ 333,636	$ 435,524	$ 327,813	$ 228,697
Purchased Power	1,253,073	1,220,759	1,448,692	1,309,505	1,301,394
Energy Cost	1,548,966	1,554,395	1,884,216	1,637,318	1,530,091
Maintenance and Other Operating Expenses	1,837,863	1,693,747	1,570,429	1,430,993	1,323,158
Adjusted Operating Expenses(3)(5)	$3,386,829	$3,248,142	$3,454,645	$3,068,311	$2,853,249
Adjusted Operating Income(3)(5)	$1,921,471	$1,577,226	$1,503,894	$1,525,449	$1,415,229
Other non-operating income and expenses, net	348,372	395,293	413,808	1,482	145,303
Contributions in aid of construction	63,915	70,492	76,942	100,865	103,459
Adjusted Change in Net Position(4)(5)	$2,333,758	$2,043,011	$1,994,644	$1,627,796	$1,663,991
Debt Service					
Adjusted Interest(5)(6)	559,487	536,274	517,818	479,482	459,413
Principal	223,610	214,040	190,315	187,683	179,405
Total debt service	$ 783,097	$ 750,314	$ 708,133	$ 667,165	$ 638,818
Debt Service Coverage Ratio	2.98	2.72	2.82	2.44	2.60
Depreciation, amortization and accretion	$ 841,217	$ 805,263	$ 761,718	$ 724,461	$ 671,090
Transfers to the Reserve Fund of the City	$ 219,312	$ 244,695	$ 232,043	$ 225,015	$ 218,355

Source: Department of Water and Power of the City of Los Angeles.
(1) Derived from the Power System Financial Statements.
(2) Net of Uncollectible Accounts.
(3) Represents total operating expenses and operating income, excluding depreciation, amortization, accretion and loss on asset impairment and abandoned projects.
(4) Represents change in net position before depreciation, amortization, accretion, interest, extraordinary loss and the Power Transfer.
(5) "Adjusted" indicates measurements of financial and/or operating performance that are not specifically disclosed in the Power System Financial Statements.
(6) Interest expense excluding amortization of debt premium.

Indebtedness

As of December 1, 2025, approximately $12.55 billion in principal amount of debt of the Department payable from the Power Revenue Fund was outstanding. Of such amount, approximately $12.40 billion in principal amount is fixed-rate bonds, and approximately $150.0 million in principal amount represents borrowings under the Department's Wells Fargo Credit Agreement (as defined below). In connection with the Department's expected five-year capital improvements to the Power System, the Department anticipates that it will fund approximately $11.9 billion of the costs of the capital improvements with proceeds of previously issued bonds and additional debt payable from the Power Revenue Fund to be issued and/or incurred through June 30, 2030. 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 July 3, 2025, the Department entered into a third amended and restated revolving credit agreement (as subsequently amended, the "Wells Fargo Credit Agreement") with Wells Fargo Bank, National Association ("Wells Fargo"), pursuant to which Wells Fargo has committed to make loans to the Department in a principal amount not-to-exceed $500 million outstanding at any one time. The Department can request loans for Power System improvements, Water System improvements and/or such other lawful purposes of the Department. Loans for Power System improvements and other lawful purposes of the Power System are payable from the Power Revenue Fund; and loans for Water System improvements and other lawful purposes of the Water System are payable from the Water Revenue Fund. As of December 1, 2025, the Department had $150 million of loans outstanding under the Wells Fargo Credit Agreement payable from the Power Revenue Fund, and $300 million of loans outstanding under the Wells Fargo Credit Agreement payable from the Water Revenue Fund. Under the Wells Fargo Credit Agreement, amounts due may be paid by the Department at any time at its option and in the event of default under the Wells Fargo Credit Agreement, amounts outstanding would be due immediately. The Department expects to pay principal amounts due under the Wells Fargo Credit Agreement and payable from the Power Revenue Fund from proceeds of subsequent borrowings or from reserves available to the Power System. Amounts borrowed under the Wells Fargo Credit Agreement and payable from the Water Revenue Fund are considered Parity Obligations under the Master Resolution. The Wells Fargo Credit Agreement currently has an expiration date of May 22, 2026.

In addition, as of December 1, 2025, 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 $3.43 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 December 1, 2025. All "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 (and the related IPP Renewal Power Sales Contract and IPP Agreement for Sale of Renewal Excess Power which will take operational effect in June 2027) 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 related IPP Renewal Power Sales Contract and IPP Agreement for Sale of Renewal Excess Power which will take operational effect in June 2027) 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 December 1, 2025, 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 December 1, 2025
(Dollars in Millions)
(Unaudited)

	Principal Amount of Outstanding Debt	Department Participation	Department Share of Principal Amount of Outstanding Debt(6)
Intermountain Power Agency			
IPP	$ 113(1)	48.62%(2)	$ 55(1)
IPP (Renewal Project)	1,695	71.44	1,211
Southern California Public Power Authority			
Mead-Adelanto Transmission Project	12	100.00(3)	12
Mead-Phoenix Transmission Project	10	100.00(3)	10
Linden Wind Energy Project	75	100.00(4)	75
Milford Wind Corridor Phase I Project	53	92.50(5)	49
Milford Wind Corridor Phase II Project	52	100.00(4)	52
Southern Transmission System (STS)	73	59.50(5)	44
STS (Renewal Project)	1,790	90.50(5)	1,620
Windy Point Project	127	100.00(4)	127
Apex Power Project	180	100.00(5)	180
Total	$4,180		$3,435

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) of 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 and other factors affect the Department and the electric utility industry. 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. This discussion does not purport to be exhaustive and these matters are subject to change after the date hereof. See "THE DEPARTMENT," "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 quarterly CARB auctions or from other entities in the secondary market. 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. When the Department sells electricity in the wholesale market, it is required to purchase allowances to cover GHG emissions for those wholesale electricity sales. The cost of those 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. Based on the 2021-2030 allowance allocation established in the 2017 amendments to the Cap-and-Trade Regulation, the Department believes that the cost of compliance with the current 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. Therefore, the Power System is currently expected to be able to continue to comply with these regulations with minimal impact to its finances or operations in connection with the implementation of the Power System's resource plan. However, as described below, CARB has initiated the process for further updates to the Cap-and-Trade Regulations. The scope of the potential amendments to be considered include, among other things, the removal of allowances from the annual allowance budget commencing in 2026 (further reducing the Statewide GHG emissions cap), revising the allowance allocation to electrical distribution utilities based on recent forecasts, and adding a requirement for POUs to consign all their allocated allowances to auction similar to investor-owned utilities. The Department could be adversely affected in the future if its GHG emissions exceed its allowance allocation or if it has to consign (sell) all of its allocated allowances to the auction and is required to purchase compliance instruments on the market to cover its emissions to meet its retail load obligations.

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 from 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 emissions 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 potential changes 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 2026 through 2030 electrical distribution utility allowance allocation based on the most recent forecasts and RPS target; a proposed new requirement 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. 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. In July 2024, CARB held a workshop to discuss potential revisions to the cap-and-trade program emission allowance budget to achieve the more ambitious emission reduction targets of 48% by 2030 and 85% by 2045, including the removal of 180 to 265 million allowances in aggregate from budget years 2026 through 2030. In October 2024, CARB posted another market notice to inform market participants about the timing and topics for the upcoming amendments to the Cap-and-Trade Regulations. At that time, CARB indicated that the formal rulemaking proposal was expected to be made available for public comment sometime in early 2025, and the amendments would take effect starting in 2026. In September 2025, AB 1207 was signed into law. AB 1207 reauthorizes and extends California's cap-and-trade program from 2030 to 2045 (which program is to be now referred to as the California Cap-and-Invest Program pursuant to the provisions of AB 1207). On September 19, 2025, CARB released a notice indicating that it would begin updating the program regulations to reflect the direction and process provided for in AB 1207 in accordance with the formal rulemaking process. The Department continues to monitor developments related to the CARB rulemaking process for potential changes to the Cap-and-Invest Program regulations.

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 carbon dioxide (“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 for such periods 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 (which target the Department expects to have satisfied, pending verification from the CEC which is expected in late 2026), 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 eligible renewable energy resources will be subject to further regulatory proceedings of the CEC. 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 five-year contract for 5.4 MW of capacity with Roseburg Forrest Products Co., in Weed, California, which began deliveries in February 2021. 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 annually (initially, beginning by January 1, 2020). 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 2025, approximately 13.4% 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. Additionally, approximately 6.5% of the Power System's overhead transmission power lines fall within a Tier 2 area and approximately 8.6% of the Power System's overhead transmission 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. In the 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. In addition, the Department has protocols in place for the blocking of re-closers on certain distribution circuits under adverse weather conditions, and may execute de-energization protocols on power lines on a per incident basis, based on operating conditions.

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 then newly created California Wildfire Safety Advisory Board (the "CWSAB"), with comprehensive revisions submitted every three years. SB 254, signed into law by Governor Newsom in September 2025, amends the provisions of AB 1054 to provide that, after January 1, 2026, POUs will instead be required to prepare and submit to the CWSAB wildfire mitigation plans at least once every four years on a schedule to be determined by the CWSAB. The Department's 2023 wildfire mitigation plan was a comprehensive update, meeting the requirements of AB 1054. The Department continues to submit its wildfire mitigation plan to the CWSAB on an annual basis. The Department was required to submit its 2024 annual update to the Department's wildfire mitigation plan to the CWSAB by July 1, 2024, which submittal was made on June 27, 2024, in satisfaction of the requirement. On December 4, 2024, the CWSAB adopted its guidance advisory opinion for the 2025 wildfire mitigation plans of POUs, based upon its review of the 2024 annual updates submitted by the POUs to their wildfire mitigation plans. The advisory opinion includes the CWSAB's recommendations to POUs for the development of updates for the POUs' 2025 wildfire mitigation plans and future comprehensive wildfire mitigation plans. The Department submitted its 2025 annual update to the Department's wildfire mitigation plan to the CWSAB by the required July 1, 2025 submission date. The 2025 wildfire mitigation plan contains ongoing program updates and historical data through calendar year 2024 and, therefore, does not contain detailed information and specific data pertaining to the January 2025 wildfires.

In March 2025, the California Department of Forestry and Fire Protection (hereinafter, "CalFire") released updated wildfire hazard severity zone maps for the Southern California region. These updated maps identify areas as "moderate," "high," and "very high" wildfire hazard severity zones in "local responsibility areas," where local fire departments are responsible for responding to fires, in order to reflect zones in California that are susceptible to wildfires. The updated maps increase the acreage in the City that is identified as a "very high" wildfire hazard severity zone and add identified areas of "moderate" and "high" wildfire hazard severity zones (which categories were not previously included in earlier versions of the CalFire fire hazard severity zone maps). These wildfire hazard severity zone maps differ from the CPUC Fire-Threat Maps referenced above. The CPUC Fire-Threat Map is designed specifically for identifying areas where there is an increased risk for utility associated wildfires. The Department will follow established protocols that use the updated CalFire wildfire hazard severity zone maps to update the Department's fire threat map in its future wildfire mitigation plans.

AB 1054 also established 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. Additional future funding for the Wildfire Fund has been provided for under the provisions of SB 254. 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 private property is damaged by a public use), California courts have imposed liability on utilities in legal actions brought by property holders for damages, where the inherent risks in the utilities' infrastructure, as deliberately designed, constructed or maintained, are determined to be a substantial cause of damage to the property. Thus, if the inherent risks associated with the facilities of a utility, such as its electric distribution and transmission lines, are determined to be the substantial cause of the plaintiff's damages, and the doctrine of inverse condemnation applies, the utility could be liable without having been found negligent. SB 1028, SB 901 and AB 1054 do not alter inverse condemnation law, which is rooted in the California Constitution. SB 254 requires the California Earthquake Authority, as administrator of the wildfire fund established pursuant to AB 1054, to, on or before April 1, 2026, in consultation with the CPUC and other specified departments and agencies of the State, and with feedback solicited from stakeholders, prepare and submit to the Legislature, and to the Governor, a report that evaluates and sets forth recommendations on new models or approaches that mitigate damage, accelerate recovery, and responsibly and equitably allocate the burdens from natural catastrophes, including catastrophic wildfires, earthquakes, and other natural disasters, across stakeholders, including insurers, communities, homeowners, landowners, governments, electrical corporations, and POUs to complement or replace the fund. Any future legal developments addressing the State's inverse condemnation doctrine, 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" for information about current litigation regarding wildfires and "THE DEPARTMENT – Insurance" for information about the Department's current insurance coverage for wildfires.

See also "THE DEPARTMENT – Los Angeles 2025 Wildfire Event" for information regarding the wildfire event that occurred in the City in January 2025.

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. Under the rule, failure to meet the NOx limits by the January 1, 2024 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 that 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 based on pollution control technology that could 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. 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 would commence a new rulemaking process that would apply to existing natural gas-fired plants and regulate additional pollutants.

On April 25, 2024, the EPA released the final rule for existing coal-fired and new natural gas-fired power plants that would limit CO_2 emissions from existing coal-fired plants and new gas-fired combustion-turbine plants based on EPA's emissions guidelines. The final rule identified a standard of performance for CO_2 emissions reflecting the application of best systems emissions reduction (BSER), which EPA determined to be CCS with 90% capture of CO_2. Under the final rule, emissions standards and guidelines were established for different subcategories of power plants according to unit characteristics such as their generating technology, capacity, level of operations, and anticipated remaining operational life of the unit.

Coal-fired generating units that planned to cease operations prior to January 2032 were exempt from the final rule. Therefore, IPP's coal units would not be subject to the emission reduction obligations under the final rule. IPP's new natural gas units, which would be considered an existing natural gas-fired power plant, would also not be subject to this final rule but would be subject to the new rule expected to be developed for existing gas-fired combustion turbines.

On June 17, 2025, the EPA published a proposed rule to repeal existing greenhouse gas emissions standards for fossil fuel-fired power plants promulgated under Section 111 of the Clean Air Act, including both the new source performance standards enacted in 2015 and the CO_2 emissions standards for existing coal-fired and new natural gas-fired power plants established under the final rules enacted in 2024, effectively eliminating existing federal GHG emissions limits for new, modified and existing electric generating units. As an alternative, the EPA also proposed to eliminate a narrower set of requirements that would include eliminating the requirements for CCS on new baseload combustion turbines and modified coal-fired units and removing emission guidelines for existing fossil fuel-fired steam electric generating units, including particularly those encouraging or requiring co-firing. On July 29, 2025, the EPA further proposed to revoke the EPA's 2009 "endangerment finding" that CO_2 and other GHGs endanger public health and welfare. The 2009 endangerment finding served as the legal basis on which the EPA regulates GHG emissions from the power, oil and gas (and auto) sectors. The outcome of these rulemakings being undertaken by the EPA in connection with its regulation of GHG emissions of power plants is not yet known.

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 finalized 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 the end of 2025, IPP will not be subject to the more stringent requirements under the final MATS rule.

On June 17, 2025, the EPA published a proposed rule to repeal the final MATs rule regulating NESHAPs from existing coal and oil-fired units. The newly proposed rule would relax standards for filterable particulate matter, ease the technology requirements on power plants to demonstrate compliance, and would raise the limit of mercury emissions allowable from lignite-fired plants. The EPA has indicated that it intends to finalize action on this proposal by the end of December 2025.

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 (i) it 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 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, sampling 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 estimated the IPP's cost of compliance with the final CCR rule (implementing the closure standards set forth in IPA's demonstration described below) to fall within the range of $55 million to $70 million (in 2019 dollars). The work to implement closure is expected to be complete in 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 focused on closure requirements for impoundments and landfills. IPA had earlier opted to comply with the alternate closure requirement as provided in the original CCR rule. The 2019 revisions included additional requirements to obtain approval from the EPA to close impoundments in accordance with the alternate closure procedures. The 2019 revisions required a demonstration that includes a plan to mitigate potential risk to human health and environmental from CCR surface impoundments. The 2019 Part A revisions were finalized and published in the Federal Register in August 2020. On November 30, 2020, IPA submitted a request to the EPA that it 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 November 30, 2025, the EPA had not yet made a substantive determination on IPP’s demonstration submission. Nonetheless, the April 2021 deadline to cease receipt of waste that would otherwise apply to 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 (aside from the EPA approval required for Part A, as described above) and is enforced primarily though citizen suits which are decided in federal district courts. This program would 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. The EPA carried out an extended public comment period on the proposed program that closed in August 2020, but as of November 30, 2025, the program had not been finalized.

In 2024, the EPA finalized revisions (Part B) to the CCR rule that included provisions to demonstrate equivalent alternate liners, using CCR for closing impoundments, and completion of closure by removal during post-closure care period. Those revisions do not impact IPA’s plan to follow alternate closure requirements.

Utah Senate Bill 161 and House Bill 3004. 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 was to have ceased operation of the IPP coal units permanently. The coal units ceased operation in late November 2025. 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’s obligation to provide the purchase option to the State with respect to one of the IPP coal-fired units remained; however, Utah H.B. 3004 also directed 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 directed environmental regulators in the State of Utah to determine whether such an application would be granted if submitted by IPA. The Utah Disposition Authority was also 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.

The Utah Disposition Authority submitted its air application with respect to the coal units by December 31, 2024, proposing to amend the provisions of IPA’s existing permit that require the coal units to cease operation following commercial operation of the IPP natural gas units. The application contemplated operation of the natural gas units at 100% of their design capacity and operation of the coal units at a 60% capacity factor. In a letter dated January 22, 2025, the State of Utah reported to the Utah Disposition Authority that, if officially submitted by IPA, the State of Utah “could approve a similar application based on the information included” in the application submitted by the Utah Disposition Authority.

Prior to the enactment of H.B. 3004, IPA stated that Utah S.B. 161 purported to create obligations for IPA that were inconsistent with IPA's obligations under federal regulations and the IPP construction and operating permits issued under federal law. 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. Pursuant to Utah S.B. 161, IPA did grant to the State of Utah an option to purchase the coal units and related assets specified in the bill. IPA has indicated that it is continuing to determine the extent of the impacts of Utah S.B. 161, as modified by Utah H.B. 3004, and to identify the appropriate course of action in response to this Utah legislation. The Department cannot predict the impacts of such legislation on the future operation of the IPP repowering project.

Although Utah law did not explicitly require IPA to submit such an application, in light of the Utah Legislature's stated intent to preserve the coal units for future operation, and demonstrated willingness to take action if IPA did not submit such an application, IPA submitted an application to amend its existing permit to construct the natural gas units as part of the IPP repowering project to allow the coal units to resume operation at a date after the natural gas units commence commercial operation. Utah House Bill 70 (discussed below) provides, however, that even after issuance of such an amended permit, the existing permit, including the requirement that the coal units cease operation and be placed in maintenance status, will remain in effect during the period that ends upon the earlier of when IPA sells the coal units or both (i) the resolution of all administrative and judicial challenges to the amended permit and (ii) the expiration of the applicable limitations period to file such challenges. Accordingly, IPA has indicated that it does not anticipate that the coal units will resume operation while IPA continues to own the coal units. In fact, Utah House Bill 70 relieves IPA of any obligation to commence operation of either coal unit during such period and contemplates that the Utah Energy Council, as established by that bill, will take title to and contract with a third party for the operation of one or both of the coal units.

On October 3, 2025, the Utah Department of Air Quality issued a permit to IPA that, in substance, approved IPA's amendment application. On October 31, 2025, the Sierra Club and Healthy Environment Alliance of Utah filed an administrative appeal before the Utah Department of Environmental Quality challenging the issuance of the permit. IPA is a party to the appeal by operation of Utah law. Briefing on the matter will proceed through 2026. IPA has indicated that it is still assessing the potential impact of the appeal.

Utah H.B. 70. During its 2025 General Session, the Utah Legislature enacted Utah House Bill 70 ("Utah H.B. 70"). The bill became effective on March 24, 2025.

The bill requires IPA to maintain, indefinitely (i) power to station service for both of the coal units, (ii) an ongoing connection of one of its coal units to the IPP Switchyard, and (iii) interconnection and switchyard facilities that will allow the remaining coal unit to be interconnected with the IPP Switchyard without the need for a new interconnection request. Utah H.B. 70 also creates the Utah Energy Council for, among other purposes, the purposes of taking title to one or both of the coal units and assuming operational responsibility for each coal unit it acquires from IPA. Utah H.B. 70 also repeals the provisions of the Utah Code establishing the Utah Disposition Authority (effectively dissolving the Utah Disposition Authority) and the provisions specifying the functions that the Utah Disposition Authority was to have performed.

IPA is working with engineering personnel to reconfigure the proposed connections of synchronous condensers to the IPP Switchyard (connecting three synchronous condensers to the IPP Switchyard at one point of interconnection as opposed to two synchronous condensers at one point of interconnection and one synchronous condenser at another). IPA is constructing the synchronous condenser facilities to provide sufficient spinning mass to allow for operation of the natural gas units as designed and to maintain the rating of IPA's transmission facilities. IPA has indicated that it believes that it will be able to comply with the requirements of Utah H.B. 70, though such requirements will result in additional costs to IPA and will diminish the redundancy that would have resulted from having two points of interconnection for the synchronous condensers to the IPP Switchyard. IPA is continuing to evaluate the future impacts of complying with Utah H.B. 70.

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 No. 1920 ("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. On November 21, 2024, FERC issued Order No. 1920-A, revising its original Order 1920 in response to numerous requests for rehearing and clarification. The revisions to Order 1920 provide state regulators with a larger role in the long-term regional transmission planning process, particularly in shaping scenario development and cost allocation, by requiring transmission providers to include state input about how future scenarios in the long-term regional transmission planning will be developed and to include any state-agreed cost allocation proposals in their compliance plans. 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 federal Administration in place at that time 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. Significant reforms and proposals in recent years have been 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.

Changing Laws, Energy Policies and Requirements

On both the state and federal levels, legislation is introduced frequently addressing domestic energy policies and various environmental matters 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 (such as expedited permitting for natural gas drilling projects, reducing regulatory burdens, climate change and water quality).

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.

The election of new officials and Administrations can also impact substantially the current environmental standards and regulations and other matters described herein. For example, since taking office in January 2025, the President of the United States has issued a series of executive orders affecting national energy policies and energy infrastructure. Among other things, such executive orders revoke a number of executive actions taken by the prior federal Administration, including revoking certain executive orders of the prior Administration relating to climate change and clean energy, requiring federal agencies to review all federal government actions taken pursuant to the revoked orders and to take necessary steps to rescind, replace or amend such actions. Such executive orders further directed an immediate pause of funding allocated to infrastructure projects under the Infrastructure Investment and Jobs Act of 2021 and the IRA during a 90-day review period. On July 4, 2025, the President signed the "One Big Beautiful Bill Act," that is expected to significantly impact the IRA's clean energy tax credits, effectively accelerating their repeal or significantly restricting them, especially those related to electric vehicles and clean electricity production. A presidential executive order has also been issued directing the heads of all federal agencies to review all agency actions affecting the development of domestic energy resources, such as oil, natural gas, coal, hydropower, biofuels, critical mineral, and nuclear energy, and within 30 days of identifying any agency action that unduly burdens the production of domestic energy resources, to develop and begin action plans to rescind or revise the agency actions. Further, the agencies were directed to notify the Attorney General so that appropriate action may be taken in any pending litigation, including the request of a stay, related to the identified agency action. A subsequent executive order issued in April 2025 instructs the Attorney General to identify and take certain actions to limit the enforcement of state and local laws, regulations, causes of action, policies, and practices burdening the development, production or use of domestic energy resources that are determined to be unconstitutional, preempted by federal law, or otherwise unenforceable, prioritizing those relating to climate change, environmental, social and governance initiatives, environmental justice, carbon or greenhouse gas emissions, and funds to collect carbon penalties or carbon taxes. Such executive order specifically identifies California's cap-and-trade program as fundamentally irreconcilable with the federal Administration's energy objectives. Another executive order directs the Secretary of Energy to establish a protocol to identify regional generation sources critical to system reliability and to prevent an identified generation resource in excess of 50 megawatts of nameplate capacity from leaving the bulk-power system or converting the source of fuel (if conversion would result in reduction of generating capacity). A number of legislative, regulatory and other actions have been taken by federal agencies pursuant to such executive orders. Certain of these actions have been the subject of judicial challenges. The Department cannot predict the outcome of these executive orders and federal actions or the impact of any future changes in the policies of the federal Administration.

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. See also "ELECTRIC RATES – Rate Setting – Proposition 26."

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.

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.

Seismic Activity; Natural Disasters

Seismic Considerations. 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 DEPARTMENT – Insurance."

Natural Disasters Generally. California is subject to geotechnical and extreme weather conditions which represent potential safety hazards, including expansive soils, wildfires, floods, high winds and areas of potential liquefaction and landslide. Identified hazards that pose a risk to the City include, but are not limited to, earthquake, adverse weather, drought, flood, coastal flood and erosion, tsunamis, wildfires, and sea-level rise. Natural disasters, severe weather-related events (which have become increasingly common), or man-made disasters or accidents, could cause significant damage to or failure of Power System infrastructure or otherwise interrupt operation of the Power System and thereby impair the ability of the Department to generate revenues. The severity and/or frequency of natural disaster occurrences may be exacerbated by the impacts of climate change.

See "THE DEPARTMENT – Los Angeles 2025 Wildfire Event" for information regarding the wildfire and windstorm event that occurred in the City in January 2025. See also "LITIGATION – Litigation Against the City and the Department Related to the Los Angeles 2025 Wildfire Event."

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 may 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.

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 herein), 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;
- Impacts of tariff-related volatility on the pricing and availability of components used in the Department's operations and capital projects that may affect costs and procurement schedules;
- 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, or renewable energy suppliers, and other electric market participants;
- 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;
- Impacts of 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.

LITIGATION

Litigation Against the City and the Department Related to the Los Angeles 2025 Wildfire Event

Multiple lawsuits have been filed, including two putative class actions (and additional lawsuits continue to be filed) against the City, the Department, and other entities by people claiming damage from the Palisades Fire. The cases are pending in the Los Angeles Superior Court. The existing lawsuits, as of December 8, 2025, consist of a number of state court actions (approximately 91 cases) filed on behalf of approximately 2,361 individual plaintiffs, including two cases filed as putative class actions on behalf of an individual and all those similarly situated that seek to certify as a class all individuals and entities in the areas impacted by the Palisades Fire who suffered property damage, loss of use, evacuation, or other harm as a result of the Palisades Fire. Pursuant to an order of the judge overseeing the litigation, on October 8, 2025, plaintiffs liaison counsel (i.e., counsel appointed to organize the plaintiffs) filed the Master Complaint containing allegations that are intended to be common to some or all of the cases. The Master Complaint, generally alleges, among other things, that: (1) the Department failed to properly maintain its water system for the purpose of fighting fires (and specifically that it failed to properly maintain the Santa Ynez Reservoir and, in certain of such cases, the Chautauqua Reservoir), (2) the Department chose to design its water system for urban use, not to fight wildfires, (3) after the fire ignited, power poles broke and the Department failed to de-energize its distribution and transmission electrical facilities, which resulted in its overhead power lines arcing and causing additional fires, and (4) the Palisades Fire was foreseeable in light of data about the history of fires in the area, current fire risk and weather. The Master Complaint also alleges that the City did not clear brush from vacant lots in Pacific Palisades, including on lots that are owned by the City, and that embers landed on this brush, sparking a spot fire. With respect to the Water System, the Master Complaint asserts claims for inverse condemnation and nuisance. With respect to the Power System, the Master Complaint asserts claims for inverse condemnation, dangerous condition of public property and nuisance. The doctrine of inverse condemnation is a "takings clause" cause of action under the State and federal constitutions that entitles property owners to just compensation if their private property is damaged by a public use. California courts have imposed liability on public agencies in legal actions brought by private property holders for damages, where the inherent risks in the public agency's infrastructure, as deliberately designed, constructed or maintained, are determined to be a substantial cause of damage to the property. The Master Complaint also alleges dangerous condition of public property and nuisance claims related to vegetation management on certain lots owned by the City. Complaints filed before the filing of the Master Complaint allege other causes of action and additional theories of liability, which certain plaintiffs may choose to maintain when adopting the Master Complaint.

The plaintiffs are seeking compensation for damages including, but not limited to, lost or damaged property, lost income or wages, and attorney's fees, and in certain of the cases loss of use/marketability of property, emotional distress, and punitive damages. Some of the pending actions seek certain injunctive relief as well as monetary damages. Most of the filed lawsuits do not contain a specific dollar amount, although one of the pending class actions asserts a damages figure of greater than $10 billion. The cases are not yet at a stage where it is possible to reasonably estimate the potential ultimate financial exposure to the City or the Department. The City and the Department deny all liability claims and intend to vigorously defend against all of these lawsuits, but cannot predict the outcome of these cases.

In addition to the City and the State, the Master Complaint added sixteen new defendants whom plaintiffs claim are responsible for their losses under a variety of tort theories and, for some, inverse condemnation. The City and the State filed demurrers challenging the sufficiency of the Master Complaint. The court has scheduled a hearing with respect to the demurrers on February 5, 2026. As of December 8, 2025, the court has stayed the City's obligation to answer or otherwise respond to any complaint, other than the Master Complaint, with respect to the litigation.

The ATF separately led the investigation into the origin and cause of the Palisades Fire. The Department provided information to the ATF and other agencies in connection with their investigations. The ATF examined the Department's overhead transmission facilities that are near, but outside of, the area where the Palisades Fire reportedly ignited. As of December 8, 2025, neither the ATF nor any other investigating authority has issued a formal cause and origin report identifying the source of the Palisades Fire (the ATF has indicated that it has completed its report). However, on October 8, 2025, the United States Department of Justice announced the arrest of Jonathan Rinderknecht, whom the United States charged in a criminal complaint with the destruction of property by means of fire. Specifically, Mr. Rinderknecht is alleged to have started the Lachman Fire in the Pacific Palisades area on the morning of January 1, 2025. According to the ATF Affidavit that was provided in connection with the criminal complaint against Mr. Rinderknecht, the multi-agency investigation into the origin and cause of the Palisades Fire determined that the Palisades Fire was a "holdover" fire (*i.e.*, a continuation of the Lachman Fire that began on January 1, 2025). The ATF Affidavit expressly ruled out power lines as a potential cause of the Lachman Fire. No investigating authority has asked the Department to preserve any of its electrical facilities in the area.

See also "THE DEPARTMENT – Los Angeles 2025 Wildfire Event."

Other Matters Related to the Power System

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 related to the Power System described below are not expected to materially impact the Power System's financial position, results of operations, or cash flows.

Other Power System-Related 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. With respect to the Getty fire, settlement agreements have been entered into with the plaintiffs and third party claims are being pursued as described below.

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 plaintiffs 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 individual plaintiffs have all dismissed their claims against the Department and have reached settlements with Edison. All of the subrogation carriers have also reached settlements with Edison. The United States has also recently reached a settlement with Edison in the federal court action. The Department is a cross-defendant for indemnity brought by Edison in the state court actions whereby Edison is seeking reimbursement from the Department for the amounts it paid in settlement. They key issue in dispute is whether the fire was caused by the Department's or Edison's power lines. The Department continues to assert that the fire was caused by Edison; therefore, Edison does not have a basis to recover anything against the Department. It is expected there will be a future trial wherein Edison will sue the Department to attempt to recover the amounts it has paid to settle lawsuits related to the Creek Fire. That trial date has not been set at this time.

If liability is found against the Department in connection with the Creek fire, an accurate exposure amount cannot now be estimated. 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.

On or about October 16, 2023, the Department settled with the insurance subrogation plaintiffs for $36.35 million, which has been paid out. On or about October 2, 2024, the Department settled with the individual plaintiff group for $45.36 million, which has also been paid out. The Department has insurance coverage with a $3 million self-insured retention for this matter. Thus, the Department is responsible for $3 million of the settlement amounts; the rest is covered by insurance.

For details regarding the extent of the Department's current insurance, see "THE DEPARTMENT – 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.