

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

Relating to:

\$116,535,000 Southern California Public Power Authority
Transmission Project Revenue Bonds,
2015 Subordinate Refunding Series C (Southern Transmission Project)

INTRODUCTION

This Annual Report is filed pursuant to the Continuing Disclosure Resolution (Resolution No. 2015-016) adopted by the Southern California Public Power Authority (the “Authority” or “SCPPA”) on February 19, 2015 (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 February 25, 2015 (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”), the City of Anaheim, California (“Anaheim”), and the City of Riverside, California (“Riverside,” and together with the Department and Anaheim, 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 certain of 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.

CERTAIN INFORMATION RELATING TO
THE SOUTHERN TRANSMISSION PROJECT

The Southern Transmission Project constitutes one of the components of the Intermountain Power Project (“IPP”). The Southern Transmission Project consists of: (a) the AC/DC Intermountain Converter Station adjacent to the IPP AC switchyard; (b) the ±500-kV DC bi-pole transmission line (“HVDC transmission line”), 488 miles in length, from the Intermountain Converter Station to the City of Adelanto, California; (c) the AC/DC Adelanto Converter Station, where the Southern Transmission Project connects to the switching and transmission facilities of the Department; and (d) related microwave communication system facilities. The HVDC transmission line is designed to have the capability of transmitting in excess of the aggregate Generation Station Production anticipated to be delivered to the Participants. The AC/DC

converter stations each consist of two solid state converter valve groups and have a combined rating of 2,400 MW. The microwave communication system facilities are used for Generation Station dispatch, for IPP communication, and for control and protection of the Southern Transmission Project. The microwave system facilities are located along two routes between the Generation Station and Adelanto, forming a loop network.

By the execution of the Construction Management and Operating Agreement (as amended, the “Construction Management and Operating Agreement”), certain participants in the IPP have designated the Department as Project Manager and Operating Agent for IPP, including the Southern Transmission Project. Actions and recommendations of the Department, in its role as Project Manager and Operating Agent, are subject to review, modification and approval by the IPP Coordinating Committee.

Status

The Southern Transmission Project has operated with excellent availability and reliability. When one pole is out of service, the Southern Transmission Project is designed to operate in a mono-polar mode at a reduced capacity rating of 1,200 MW. Because the Southern Transmission Project is designed to operate in this manner, reliability for system planning purposes is essentially equivalent to that of two AC transmission lines.

During the fiscal year ended June 30, 2025, transmission availability (one or both poles on) was approximately 97.99%. Scheduled outages are largely controlled to occur simultaneously with scheduled generating unit outages and thus do not interfere significantly with scheduled energy deliveries.

In the fiscal year ended June 30, 2025, the Participants received approximately 7.46 million MWh of energy over the line, consisting of a majority from IPP and the balance from Milford Wind Corridor Phase I Project, Milford Wind Corridor Phase II and various other purchases by certain of the Participants.

Arrangements for Transmission Service from the Adelanto Converter Station

The Department has constructed a station and associated facilities to connect the Adelanto Converter Station with the Department’s main transmission system. The Department takes delivery of its share of the Intermountain Power Project Generating Station entitlements at the Adelanto Converter Station and provides transmission service for three of the other five Participants. The Department transmits the generation entitlements of the Cities of Glendale and Burbank directly to those cities’ respective systems. The Cities of Anaheim, Pasadena, and Riverside use transmission services from the California Independent System Operator.

Additionally, certain of the Participants will utilize their capacity rights in the IPP switchyard, provided under agreements relating to the IPP, to accept energy delivered from the Authority’s Milford Wind Corridor Phase I Project and the Milford Wind Corridor Phase II Project, as well as from certain other projects not owned by the Authority, over the Southern Transmission System to the Adelanto terminal in California. The energy delivered at Adelanto is transmitted to the Participants’ respective electric systems under existing transmissions service arrangements.

The rights of the Participants under their existing IPP agreements for the delivery of the generation entitlements over the Southern Transmission System terminate on June 15, 2027.

Intermountain Power Project Fuel Supply

The Intermountain Generating Station’s annual coal requirement is approximately 900,000 tons in calendar year 2025. The Department, in its role as the operating agent of the IPP, buys coal on behalf of the Intermountain Power Agency (“IPA”) under contracts to fulfill this supply requirement of the IPP. 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.

Permits, Licenses and Approvals

The Southern Transmission Project was designed and constructed to operate in compliance with applicable federal, state and local regulations, codes, standards and laws. The Authority believes that all necessary permits, licenses and approvals have been secured.

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
Southern Transmission System Project
Statement of Net Position
(In thousands)**

	Fiscal Year Ended June 30,	
	2025	2024
ASSETS		
Noncurrent assets		
Net utility plant	\$83,903	\$87,949
Investments – restricted	26,859	26,710
Advances to IPA – restricted	<u>10,930</u>	<u>10,930</u>
Total noncurrent assets	<u>121,692</u>	<u>125,589</u>
Current assets		
Cash and cash equivalents – restricted	9,845	9,457
Cash and cash equivalents – unrestricted	534	391
Interest receivable	56	46
Accounts receivable	5,894	170
Prepaid and other assets	<u>29</u>	<u>25</u>
Total current assets	<u>16,358</u>	<u>10,089</u>
DEFERRED OUTFLOWS OF RESOURCES		
Unamortized loss on refunding	<u>1,081</u>	<u>3,011</u>
Total deferred outflows of resources	<u>1,081</u>	<u>3,011</u>
Total assets and deferred outflows of resources	<u>\$139,131</u>	<u>\$138,689</u>
LIABILITIES		
Noncurrent liabilities		
Long-term debt	<u>\$62,567</u>	<u>\$92,684</u>
Total noncurrent liabilities	<u>62,567</u>	<u>92,684</u>
Current liabilities		
Debt due within one year	28,390	27,055
Accrued interest	2,182	2,850
Accounts payable and accruals	<u>6,348</u>	<u>467</u>
Total current liabilities	<u>36,920</u>	<u>30,372</u>
Total liabilities	<u>99,487</u>	<u>123,056</u>
NET POSITION		
Net investment in capital assets	(5,973)	(28,779)
Restricted	45,508	44,293
Unrestricted	<u>109</u>	<u>119</u>
Total net position	<u>39,644</u>	<u>15,633</u>
Total liabilities and net position	<u>\$139,131</u>	<u>\$138,689</u>

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
Southern Transmission System Project
Statement of Revenues, Expenses and Changes in Net Position
(In thousands)**

	Fiscal Year Ended June 30,	
	2025	2024
Operating revenues:		
Sale of transmission services	<u>\$75,471</u>	<u>\$68,198</u>
Total operating revenues	<u>75,471</u>	<u>68,198</u>
Operating Expenses:		
Operations and maintenance	43,882	36,810
Depreciation, depletion, and amortization	<u>4,046</u>	<u>4,046</u>
Total operating expenses	<u>47,928</u>	<u>40,856</u>
Operating income (loss)	<u>27,543</u>	<u>27,342</u>
Non-operating revenues (expenses)		
Investment and other income	1,035	728
Other interest and debt expense	<u>(4,567)</u>	<u>(5,202)</u>
Net non-operating revenues (expenses)	<u>(3,532)</u>	<u>(4,474)</u>
Change in net position	24,011	22,868
Net position – beginning of year	<u>15,633</u>	<u>(7,235)</u>
Net position – end of year	<u>\$39,644</u>	<u>\$15,633</u>

Operating Statistics

The operating results of the Intermountain Power Project Generating Station during the last five fiscal years are shown in the following table. Based on historical experience of comparable generating units, the Authority currently expects that over the life of the plant the Intermountain Power Project Generating Station will continue to achieve the above-average levels of performance demonstrated to date.

Operating Statistics

	Fiscal Year <u>2020-21⁽¹⁾</u>	Fiscal Year <u>2021-22⁽²⁾</u>	Fiscal Year <u>2022-23⁽³⁾</u>	Fiscal Year <u>2023-24⁽⁴⁾</u>	Fiscal Year <u>2024-25⁽⁵⁾</u>	Industry Average Calendar Years <u>2020-24⁽⁶⁾</u>
Gross Energy Generated (MWh)						
Unit 1	3,808,747	3,126,525	2,764,193	2,739,388	3,820,066	3,847,525
Unit 2	4,070,442	2,969,883	3,714,375	1,873,221	3,642,040	3,847,525
Net Energy Generated (MWh)						
Unit 1	3,537,724	2,873,350	2,538,344	2,496,799	3,525,815	3,463,204
Unit 2	3,763,675	2,731,012	3,418,622	1,649,669	3,346,890	3,463,204
Plant Capacity Factor⁽⁷⁾						
Unit 1	44.87%	36.45%	32.20%	31.58%	44.72%	39.66%
Unit 2	47.74%	34.64%	43.36%	20.87%	42.45%	39.66%
Operating Availability⁽⁸⁾						
Unit 1	85.20%	95.66%	88.07%	100.00%	99.89%	80.57%
Unit 2	94.91%	84.02%	97.16%	91.00%	99.32%	80.57%
Equivalent Availability⁽⁹⁾						
Unit 1	85.17%	95.66%	87.80%	100.00%	99.21%	78.08%
Unit 2	94.36%	83.87%	97.16%	90.94%	90.94%	78.08%
Net Unit Heat Rate (BTU/kWh)⁽¹⁰⁾						
Unit 1	10,174	10,227	10,182	10,469	10,332	11,155
Unit 2	10,247	10,122	10,167	10,941	10,317	11,155

- (1) Reflects the following 2020-21 scheduled maintenance outages and forced outages: Unit 1 Spring (7 weeks) and Unit 2 Spring 2021 (9.2 days). Unplanned maintenance outages: Unit 1 (3.2 days) and Unit 2 (5.9 days); and forced outages: Unit 1 (0.07 days) and Unit 2 (3.4 days).
- (2) Reflects the following 2021-22 scheduled maintenance outages and forced outages: Unit 2 Spring 2022 (8.3 weeks) and Unit 1 Spring 2022 (11.8 days). Unplanned maintenance outages: Unit 1 (0.0 days) and Unit 2 (0.0 days); forced outages: Unit 1 (4.0 days) and Unit 2 (0.28 days); and reserve shutdown for coal conservation: Unit 1 (8.9 weeks) and Unit 2 (8.1 weeks).
- (3) Reflects the following 2022-23 scheduled maintenance outages and forced outages: Unit 1 Spring 2023 (6.2 weeks) and Unit 2 Spring 2023 (9.9 days). Unplanned maintenance outages: Unit 1 (0.0 days) and Unit 2 (0.0 days); and forced outages Unit 1 (4.4 hours) and Unit 2 (10.4 hours). Reserve Shutdown for coal conservation: Unit 1 (12.3 weeks) and Unit 2 (9.2 weeks).
- (4) Reflects the following 2023-24 scheduled maintenance outages and forced outages: Unit 1 Spring 2024 (0.0 weeks) and Unit 2 Spring 2024 (4.4 weeks). Unplanned maintenance outages: Unit 1 (0.0 days) and Unit 2 (1.9 days); and forced outages Unit 1 (0.00 hours) and Unit 2 (13.3 hours). Reserve Shutdown for coal conservation: Unit 1 (11.9 weeks) and Unit 2 (18.8 weeks).
- (5) Reflects the following 2024-25 scheduled maintenance outages and forced outages: Unit 1 Spring 2025 (0.0 days) and Unit 2 Spring 2025 (0.0 days). Unplanned maintenance outages: Unit 1 (0.0 days) and Unit 2 (1.45 days); and forced outages: Unit 1 (0.40 days) and Unit 2 (1.03 days). Reserve shutdown: Unit 1 (42.65 days) and Unit 2 (66.57 days).
- (6) Industry average figures except heat rate are as reported by NERC for coal-fired units rated 800-999 MW and are the composite averages of 51 units in the years 2020 through 2024 (5-year average), which is the most recent information currently available. Average net station heat rate is compiled and cited from Form EIA-923 released by the Energy Information Administration of the U.S. Department of Energy ("EIA") for 2024 for the top 25 largest western coal-fired power plants. Such NERC and EIA reports are calendar-year based.
- (7) The Plant Capacity Factor for a unit is the ratio of the net energy generated by that unit to the net maximum capability of that unit times the hours in the period and reflects the unit availability as well as the actual power produced by the unit.
- (8) The Operating Availability is the ratio of hours in the period that the unit is capable of operating at some level to the number of hours in the period.
- (9) The Equivalent Availability factor provides an adjustment of the Operating Availability by incorporating the effect of de-ratings (losses in MW capability) and is essentially equivalent to the percentage of time during a period during which a unit was available for maximum net capability operation.
- (10) The Unit Heat Rate is a measure of the efficiency of the unit and shows the amount of heat energy in BTUs necessary to produce 1.0 net kWh. The smaller this number is, the more efficient the unit.

FINANCIAL STATEMENTS

The audited financial statements of the Authority, the Department and Anaheim for the fiscal year ended June 30, 2025, are attached hereto. The unaudited financial statements of Riverside for the fiscal year ended June 30, 2025, are attached hereto. The audited financial statements of Riverside for the fiscal year ended June 30, 2025 will be filed with the Municipal Securities Rulemaking Board’s Electronic Municipal Market Access System for Municipal Securities disclosures once their audited financial statements are available to the public and the Authority.

ESTIMATED DEBT SERVICE REQUIREMENTS

The following table sets forth the estimated debt service requirements for the bonds relating to the Southern Transmission Project:

Fiscal Year Ending June 30,	(Accrual Basis)		Combined Debt Service
	<u>Subordinate Bonds</u>		
	<u>Principal</u>	<u>Interest</u>	
2026	\$29,805,000	\$2,946,150	\$32,751,150
2027	<u>31,285,000</u>	<u>1,462,000</u>	<u>32,747,000</u>
Total ⁽¹⁾	<u>\$61,090,000</u>	<u>\$4,408,150</u>	<u>\$65,498,150</u>

⁽¹⁾ Total may not add due to rounding.

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 which is set forth in Appendix D to the Official Statement.

THE CITY OF ANAHEIM

The following is information concerning the City of Anaheim (“Anaheim” or, in this section, the “City”), its Public Utilities Department (“Anaheim Public Utilities” or “APU”) and such APU’s electric utility (the “Anaheim Electric System” or the “Electric System”), prepared by Anaheim for inclusion herein. This information does not purport to cover all aspects of the business, operations and financial position of the Anaheim Electric System.

Organization

The City of Anaheim is a chartered city of the State of California. Under the provisions of the California Constitution, the Charter of the City of Anaheim (the “Charter”) and Title 10 of the Municipal Code of the City, the City owns and operates both the Electric System and a water system (the “Water System”) for the citizens of the City. APU exercises jurisdiction over both the Electric System and the Water System and is under the supervision of the Public Utilities General Manager (the “General Manager”). The General Manager supervises the design, construction, maintenance and operation of both the Electric System and the Water System. The Finance Director/City Treasurer oversees the accounting and administration of the financial affairs of the City. The Anaheim City Council (the “City Council”) appoints the City Manager, who provides direction to the General Manager and Finance Director/City Treasurer.

The Electric System and the Water System provide services to virtually all residential, commercial, and industrial customers within 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.

Management of Anaheim Public Utilities

The following are biographical summaries of the executive management team of APU with responsibility for the Electric System:

Dukku Lee, Public Utilities General Manager, has served Anaheim Public Utilities since November 1999 and was appointed as its General Manager in November 2013. He has full management responsibility to plan, direct, and manage APU’s day-to-day activities and operations. Mr. Lee began his career in the utility industry in 1993. Prior to his appointment as General Manager, Mr. Lee held the position of Assistant General Manager–Electric Services with responsibility for managing the engineering, construction, operation and maintenance of the utility generation, transmission, and distribution system. Mr. Lee previously worked for Southern California Edison (“Edison”) and Paragon Consulting Services. Mr. Lee holds a Bachelor of Science degree in Electrical Engineering from California State Polytechnic University, Pomona and a Master of Science degree in Engineering Management from California State University, Long Beach and is a registered Professional Engineer in the State of California. Mr. Lee is on the Board of Directors of the Southern California Public Power Authority (“SCPPA”) and the Board of Governors of the California Municipal Utilities Association (“CMUA”).

Brian Beelner, Assistant General Manager–Finance & Energy Resources, has served Anaheim Public Utilities since 2005. He is responsible for multiple aspects of APU including accounting, budget development, financial planning, rate design, long-term forecasting, debt administration, warehousing and supply chain, power supply, and information technology. Prior to joining the City, Mr. Beelner worked for Gursey, Schneider & Co., LLP as a municipal utility accounting and finance consultant. Mr. Beelner graduated from the University of California, Riverside with a Bachelor of Arts degree in Business Economics and currently holds an active Certified Public Accountant license in the State of California. He is a member of the SCPPA Finance Committee and an alternate member of SCPPA’s Board of Directors, a

member of the Coordinating Committee for the Intermountain Power Project (“IPP”), and a member of the San Onofre Nuclear Generating Station Decommissioning Executive Committee.

Janet Lonneker, Assistant General Manager–Electric Services, joined Anaheim Public Utilities in May 2014, and is responsible for directing, managing, supervising, and coordinating the activities and operations of the Electric Services Division, including electrical engineering, electric operations, system planning, substations, and power generation. Ms. Lonneker has over 25 years of electric utility industry experience, most recently before joining Anaheim as a Customer Solutions Manager for San Diego Gas and Electric (“SDG&E”) where she worked within the Smart Grid Division. Prior to her employment at SDG&E, she was General Manager for the City of Forest Grove’s Department of Light and Power for six years, where she was responsible for leadership, management, and oversight of all divisions of the utility. Ms. Lonneker holds a Bachelor of Science degree and a Master of Science degree in Electrical Engineering from the University of the Pacific and the University of Southern California, respectively.

Janis Lehman, Assistant General Manager–Administration & Risk Services, has been with Anaheim Public Utilities since 1990. She currently leads the Administration and Risk Services Division which is responsible for enterprise risk management, environmental and regulatory compliance, safety services, legislative and regulatory affairs, and customer service including credit collections and billing. She has experience in all key aspects of the water and electric utility industry. She started her career at APU managing transmission line and power generation projects, as well as developing water programs. Her career path has included working as a hazardous materials design specialist for water and soil projects, a first responder on hazardous materials emergency response teams, and as an engineer at Bechtel Engineering before coming to APU. She has taught several courses on regulatory compliance through California State University. Ms. Lehman currently serves as an alternate on the CMUA Board of Governors. She is a member and past chair of the CMUA Legislative Committee and the Regulatory committee. She is also a member and past chair of the SCPPA Risk Management Committee, a member of the Credit Working Group of the California Independent System Operator Corporation (“CAISO”), and has testified as an expert witness at the California Public Utilities Commission (“CPUC”). Ms. Lehman has a Bachelor of Science degree in Geophysics from University of California, Riverside, and a Master of Business Administration degree from the University of Southern California.

Public Utilities Board

The City Council, by Ordinance No. 3557 approved July 6, 1976, established a Public Utilities Board (the “Public Utilities Board” or the “Board”) with the power and duty to make recommendations to the City Council for consideration by the City Council in its determinations concerning (i) the operation and conduct of the Electric System and the Water System, (ii) the establishment of rules and regulations and rates for the operation of the Electric System and the Water System, (iii) the duties and qualifications of the General Manager and other APU employees, (iv) the acquisition, construction, improvement, extension, enlargement, diminution or curtailment of all or any part of the Electric System and the Water System, (v) APU’s annual budget, and (vi) financing, including the issuance of bonds for the Electric System and the Water System. On June 3, 2014, City voters approved Measure C which, among other things, added Section 909 to the Charter specifying the powers and duties of the seven-member Public Utilities Board. The Board may also exercise such other powers and duties as may be prescribed by ordinance not inconsistent with the Charter.

The Board consists of seven members, none of whom may hold any paid office or employment in the City government. The members of the Board are appointed by the City Council and may be removed by a majority vote of the City Council. Board members serve four-year overlapping terms and are limited to serving two consecutive four-year terms.

The present members of the Board and their terms of appointment are:

John Seymour, Chairperson, term expires December 31, 2026. Mr. Seymour joined the Board in April 2017, and was reappointed in January 2023. He is a retired telecommunications executive with a bachelor's degree from Whittier College in Economics and Business Administration with an emphasis in Accounting. Mr. Seymour previously served on the City's Planning Commission (2010-2017), and is a former member and chair of the Public Utilities Board's Underground Conversion Subcommittee. He served on the board for the Anaheim Regional Medical Center for over twenty years, and served as a board member for Memorial Health Services.

Anh Pham, M.Ed., Vice Chairperson, term expires December 31, 2025. Mr. Pham joined the Board in February 2022. He is a civil rights administrator for the University of California, Irvine, and prior to that, spent a decade working for the University of California, Riverside. He earned a Bachelor of Arts degree in Public Policy as well as a Master of Education in Higher Education Administration and Policy from the University of California, Riverside.

Albert McMenamain, term expires December 31, 2026. Mr. McMenamain joined the Board in January 2023. He began his career with the City. During his 37-year career, he worked in the water services division and held the positions of Equipment Operator, Maintenance Pipefitter and Senior Water Utility Inspector. Mr. McMenamain has also worked part time with the Los Angeles Angels since 2001.

Mitch Lee, term expires December 31, 2028. Mr. Lee joined the Board in August 2021. He retired from the Boeing Company after 20 years as a Deputy Project Manager. Previously, Mr. Lee worked at Northrop Grumman Corporation for 13 years as an engineer. Throughout his career, he worked on several U.S. Government, international and commercial programs. Currently, he is a consultant and an advisory board member for Theory Seventy Three Corp.

Talab Ibrahim, term expires December 31, 2028. Mr. Ibrahim joined the Board in February 2023. He attended California State University, Fullerton where he earned his Bachelor of Science degree in Civil Engineering. In college, he joined the American Society of Civil Engineers and Institute of Transportation Engineers. Currently, he manages a family business in Anaheim and serves as a property manager at family-owned properties in Orange County.

Ivan Castillo, term expires in December 31, 2028. Mr. Castillo joined the Board in August 2025. He earned his bachelor's degree in Political Science from Loyola Marymount University in 2004. Mr. Castillo spent 17 years with the Irvine Company. He currently serves as a Business Advisor at Insperity, supporting small and mid-sized businesses across Southern California.

Hon. Shashi H. Kewalramani (Ret.), term expires December 31, 2026. Mr. Kewalramani joined the Board in November 2025. He currently serves as a mediator and arbitrator with JAMS, a national organization providing private dispute-resolution services, following a distinguished career on the federal bench and in public service. He previously served as a U.S. Magistrate Judge for the Central District of California and, before that, as an Assistant U.S. Attorney in both the Northern and Central Districts of California, where he handled complex cybersecurity, fraud, and intellectual-property matters. Mr. Kewalramani also possesses private-sector experience representing clients in intellectual-property and commercial litigation. He earned his J.D. from Baylor University School of Law and a B.S. in Aerospace Engineering from the University of Texas at Austin.

History of the Electric System

The Anaheim Electric System was established in 1894. The original City-owned generating plant was placed in service in 1895 and consisted of a steam-driven generator of 500 lights capacity. By 1896, the maximum capacity of the original generating plant had been reached and City voters authorized bonds for the combined rebuilding of both the electric light plant and the City's water system. In 1916, the City negotiated to purchase all of its power from Edison. In the years that followed, the City challenged rate increases and other measures undertaken by Edison, ultimately resulting in a settlement between Edison and the City in 1972 that permitted the City to take advantage of lower-cost power resources.

From 1976 to 1983, the City continued to purchase a majority of its power supply from Edison. During that span, the City also purchased energy from Nevada Power and other utilities in the western United States. Also during this period, the City voters supported a series of revenue bond issues and other financing options to allow the utility to participate in a power diversification process. Included in this process was the City joining SCPPA, a joint exercise of powers authority created for planning, financing, developing, acquiring, constructing, improving, operating, and maintaining electric generating and transmission projects for participation by some or all of its members.

By the late 1980s and early 1990s, the City received power from a variety of sources, including contractual arrangements for capacity and energy, a 40 megawatts ("MW") share of power generated at the Hoover Dam, and ownership interests in projects such as the San Juan Generating Station ("SJGS" or "San Juan") in New Mexico. As a result of the City's efforts to diversify its electric generating power resources, the City purchased less than 2% of its energy from Edison in 1997, and by 2002, the City did not purchase any of its energy requirements from Edison.

During this period, the City also began developing a project to remove overhead power lines and poles on major public roads. The City Council approved a recommendation from the Public Utilities Board to establish an underground utility conversion program in 1991, which aimed to improve the Electric System's reliability by hardening the system against outages caused by weather, metallic balloons, and vehicle accidents, while also beautifying the City's streets and enhancing property values.

Today, the City's power is produced at generating plants in or near the City and at locations across the western United States. The Electric System serves the entire area of the City, covering approximately 50 square miles of the northern portion of Orange County, which is about 28 miles southeast of downtown Los Angeles, and about 90 miles north of San Diego. The City lies on a coastal plain which is bordered by the Pacific Ocean to the west and the Santa Ana Mountains to the east. For the Fiscal Year ended June 30, 2025, the Electric System served an average of 125,065 customers and sold approximately 2,786,879 megawatt-hours ("MWh") of energy.

The table below sets forth historical Electric System resources:

**TABLE 1
HISTORICAL RESOURCES
CAPACITY (MW)**

	Fiscal Year Ended June 30				
	2025	2024	2023	2022	2021
<u>Non-City Owned Resources</u>					
Hoover	40	40	40	40	40
IPP	236	236	236	236	236
Magnolia	118	118	118	118	118
Canyon Power Project ⁽¹⁾	200	200	200	200	200
<u>Non-City Owned Renewable Resources</u>					
Ormat Technologies	-	-	-	8	8
PPM Energy	30	32	32	32	32
Brea Power Partners	27	27	27	27	27
Cyrq Energy, Inc. subsidiary ⁽²⁾	7	7	7	7	7
San Gorgonio Farm	31	31	31	31	31
Haypress	13	-	-	-	-
MWD Hydro ⁽³⁾	-	10	10	10	10
Bowerman Power	20	20	20	20	20
Westlands (Westside Solar, LLC)	2	2	2	2	2
Loyalton (ARP Loyalton Cogen, LLC) ⁽⁴⁾	-	-	-	1	1
Desert Harvest II	36	36	36	36	36
Total Resources	760	759	759	768	768

(1) See “ - Power Supply Resources - Non-City Owned Resources – Canyon Power Project” below.

(2) Cyrq Energy, Inc.’s former name was Raser Technologies.

(3) Through SCPPA, the City contracted with the Metropolitan Water District of Southern California (MWD) for a 56.5% share – approximately 9.7 MW – from four small hydroelectric plants located in the Los Angeles Basin between November 1, 2008, through December 31, 2023.

(4) The City last received power from the Loyalton Project in calendar year 2020; the 1 MW shown under Fiscal Years 2022 and 2021 represents the project nameplate capacity before the City terminated its purchase power agreement on April 19, 2023.

Source: Anaheim.

The City’s power supply is derived from a variety of electric generating resources in order to provide lower rates and reliable service to its customers. The City supports environmentally sound energy generation, and continues to increase renewable resources as part of its overall power portfolio. See “Power Supply Resources – Renewable Energy Resources” below.

Principal Facilities

The Electric System includes generation, transmission and distribution facilities. As of June 30, 2025, the Electric System’s principal facilities consisted of approximately 1,263 circuit miles of transmission and distribution lines, and 14 distribution substations.

The City also purchases power and transmission service from other entities. See “Power Supply Resources – Non-City Owned Resources” below.

The following table sets forth information relating to the assets, production capacity, and production costs, per category of resource, of the Electric System for the five fiscal years shown:

TABLE 2
ELECTRIC SYSTEM STATISTICS
(\$000)

	Fiscal Year Ended June 30,				
	2025	2024	2023	2022	2021
Investment in Utility Plants:					
Production	\$ 46,103	\$ 46,103	\$ 46,103	\$ 46,103	\$ 46,103
Transmission	122,526	113,877	113,886	113,823	109,011
Distribution	1,348,412	1,300,291	1,292,161	1,262,770	1,194,849
General	170,933	165,686	163,076	161,162	154,792
Right to use asset - Land	3,901	3,901	3,200	3,200	-
Right to use asset - Equipment	334	-	-	-	-
Subscription base assets (SBITA)	<u>2,675</u>	<u>658</u>	<u>658</u>	<u>658</u>	<u>-</u>
Gross utility plant	1,694,884	1,630,516	1,619,084	1,587,716	1,504,755
Less—accumulated depreciation	<u>(833,535)</u>	<u>(785,302)</u>	<u>(737,607)</u>	<u>(693,299)</u>	<u>(649,346)</u>
Net plant in service	861,349	845,214	881,477	894,417	855,409
Land	34,243	34,243	34,243	34,243	34,243
Construction work in progress	<u>250,105</u>	<u>190,470</u>	<u>134,139</u>	<u>99,346</u>	<u>123,368</u>
Total utility plant	<u>\$1,145,697</u>	<u>\$1,069,927</u>	<u>\$1,049,859</u>	<u>\$1,028,006</u>	<u>\$1,013,020</u>
Production Costs					
Owned Generation ⁽¹⁾	\$ -	\$ -	\$ 265	\$ 399	\$ 68
Purchased Power ⁽²⁾	<u>206,821</u>	<u>196,788</u>	<u>232,720</u>	<u>208,152</u>	<u>192,618</u>
Total Production Costs	<u>\$ 206,821</u>	<u>\$ 196,788</u>	<u>\$ 232,985</u>	<u>\$ 208,551</u>	<u>\$ 192,686</u>
Transmission-69 kV Circuit Miles	89	89	89	89	89
Distribution Overhead Circuit Miles	383	384	389	389	391
Underground Circuit Miles	791	783	769	769	764
Transformer Capacity (in kVA)					
220 kV to 69 kV	1,808,000	1,808,000	1,808,000	1,808,000	1,808,000
69 kV to 12 kV	1,325,800	1,325,800	1,325,800	1,325,800	1,325,800
12 kV to Customer	1,887,097	1,832,239	1,832,239	1,832,239	1,910,561

⁽¹⁾ Cost information includes debt service on facilities during the fiscal period. See “ - Power Supply Resources” for discussion of reduction in City-owned generation.

⁽²⁾ Excludes transmission costs and gas sold.

Source: Anaheim.

In the Fiscal Year ended June 30, 2025, the City purchased approximately 3,059 gigawatt-hours (“GWh”) of electricity. Combined customer electric requirements created the historic distribution system peak demand of 593 MW on July 24, 2006. The following table sets forth the total Electric System GWh of energy purchased and electric distribution system peak demand during the five fiscal years shown:

**TABLE 3
TOTAL GIGAWATT HOURS (GWh) GENERATED
AND PURCHASED AND PEAK DEMAND (MW)**

	Fiscal Year Ended June 30,				
	2025	2024	2023	2022	2021
<u>Firm Purchases:</u>					
Intermountain Power Project.....	927	592	761	805	1,063
Hoover Uprating Project	33	31	30	38	41
Magnolia Power Project	489	564	581	553	418
Canyon Power Project ⁽¹⁾	54	90	127	99	99
Renewable Resources ⁽²⁾	<u>961</u>	<u>735</u>	<u>666</u>	<u>732</u>	<u>696</u>
Subtotal	2,464	2,012	2,165	2,227	2,317
<u>Non-Firm Purchases:</u>					
System Total Energy Generated and Purchased, GWh ⁽³⁾	<u>595</u>	<u>610</u>	<u>557</u>	<u>554</u>	<u>429</u>
Distribution System Peak Demand, MW	3,059	2,622	2,722	2,780	2,746
	579	500	566	487	559

⁽¹⁾ Canyon Power Project is a peaking unit, and total generation each year varies based on demand and market prices.

⁽²⁾ Renewable resources vary by year, but meet the RPS requirements, sometimes supplemented with renewable energy credits (“RECs”).

⁽³⁾ Includes energy purchased that was ultimately sold in the wholesale market. Also includes RECs purchased. Totals may not add due to rounding.

Source: Anaheim.

Power Supply Resources

The City’s electric resources currently consist of power from firm purchases with entitlements in the IPP of the Intermountain Power Agency (“IPA”), in the Hoover Uprating Project of the federal government, and in SCPPA’s Magnolia Power Project and Canyon Power Project (in which the City has an entitlement to 100% of the capacity and energy thereof), and firm power purchases and non-firm energy purchases from other utilities, which can include a number of renewable energy resources. Each of these resources is more fully described below. The City’s resources previously included the City-owned Kraemer Combustion Turbine (“CT”) Power Plant (the “Kraemer CT Plant”) and ownership interests in the SJGS and the San Onofre Nuclear Generating Station (“SONGS”). The City has retired the Kraemer CT Plant from operation and divested its ownership interests in the latter two resources but retains certain environmental and decommissioning obligations, which are described in more detail below.

Previous City Resources

Kraemer CT Plant. The City owned 100% of the Kraemer CT Plant, a natural gas-fired combustion turbine plant located in the northeast part of the City, adjacent to the City’s Dowling Substation. The Kraemer CT Plant began operation in May 1991 and ceased operations in March 2019 due to required turbine repairs. The City permanently ceased operation of the Kraemer CT Plant as of December 31, 2019 because the repair of the turbine was impractical and cost prohibitive due to the scarcity of repair parts for the turbine’s model. Furthermore, there appeared to be only one vendor who could service and repair the turbine and that vendor was expected to cease depot repair of this turbine model on or about December 31, 2022. Demolition of the plant was completed in June 2025, at an approximate cost of \$400,000.

San Juan Generating Station Unit 4. In April 1991, the City purchased a 10.04% (50 MW) undivided ownership interest in Unit 4 of the San Juan Generating Station (“SJGS”), located in San Juan County in northwestern New Mexico, near Farmington, New Mexico. The SJGS is a four-unit coal-fired steam electric generating plant. Unit 4 had a rated net generating capability of 507 MW (as of December 31, 2017). Public Service Company of New Mexico constructed Unit 4 and manages its operations. The City

purchased its 50 MW share in Unit 4 for a price of \$55 million, which the City financed through revenue bonds of the Electric System. The City ceased to have an ownership interest in the SJGS effective December 31, 2017; approximately 182 GWh of energy was provided to the City from its San Juan Unit 4 ownership interest in the Fiscal Year ended June 30, 2018, prior to such date.

In connection with divestiture by the City and other participants from the plant and a restructuring thereof, the City (along with the other exiting participants) retains certain liabilities for its respective share of the costs of the SJGS decommissioning and pre-exit date mine reclamation costs. The City's proportionate share of decommissioning costs is 2.7%, following the retirement of SJGS from service in October 2022. The total estimated cost to complete decommissioning is \$70 million, with the City's share estimated at \$1.9 million. Decommissioning activities are in progress with an estimated completion in 2026. However, certain ponds and pumps will remain operational to support reclamation activities and monitoring through 2040.

The City's share of reclamation is 3.1% of all pre-2017 year-end mining activities. The total estimated cost to complete reclamation, including both pre- and post-2017 mining activities, is approximately \$148 million, with the City's share estimated at approximately \$4.5 million. Reclamation is anticipated to be completed by 2040.

The City has fulfilled its required contributions to the mine reclamation trust funds and has funded the SJGS decommissioning trust fund for plant decommissioning activities. Annual contributions to the decommissioning trust fund will continue through the completion of decommissioning, with funding levels aligned to the work scheduled for each year.

San Onofre Nuclear Generating Station. Until 2007, the City's interest in the San Onofre Nuclear Generating Station ("SONGS") was the most significant City-owned generation resource in its portfolio. Under agreements with Edison, the City acquired a 3.16% ownership interest in SONGS Units 2 and 3, totaling 1,070 MW and 1,080 MW of capacity, respectively. Maintenance and operation of SONGS remained the responsibility of Edison under an operating agreement with the City (the "SONGS Operating Agreement") and other agreements with various participants. As a result of the transfer of the City's ownership interest in SONGS to Edison at the end of 2006, none of the City's firm power supply has been obtained from SONGS since 2007.

After a number of developments at the plant and numerous meetings in the public sphere and with the United States Nuclear Regulatory Commission (the "NRC"), Edison announced on June 7, 2013 its intention to permanently cease power generation operations and shut down Units 2 and 3. On August 19, 2021, Edison submitted a decommissioning cost analysis study to the NRC. Based upon Edison's most recent decommissioning cost study, amounts previously funded by the City and held in trust are expected to fully fund the City's share of SONGS decommissioning costs; however, until the actual total overall decommissioning costs are finally determined, no assurance can be given that additional contributions will not be required by the City. A decommissioning general contractor was selected in December 2016 to decontaminate and dismantle the facility. The decommissioning work is scheduled to be completed by the end of 2028, and full site restoration is expected to be completed by the end of 2051.

Non-City Owned Resources

The City purchases power from other sources pursuant to contracts. These contracts provide generally for the City to pay costs associated with the firm purchase of power (fixed costs) as well as operations, maintenance and administrative expense (variable costs). Information regarding the total cost of power purchased from these facilities is set forth in the table captioned "Electric System Statistics." With respect to each of the facilities discussed herein other than the Canyon Power Project, the City is one of several purchasers of such power and does not control the operations or management of such facility.

Intermountain Power Project. IPA constructed and placed into operation the IPP. The IPP consists of: (a) a two-unit, coal-fired, steam-electric generating plant with a net rating of 1,800 MW (the “Intermountain Generating Station”) and a switchyard (the “Switchyard”), located near Lynndyl, in Millard County, Utah; (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 “Transmission Resources – Southern Transmission System” below); (c) two 50-mile, 345-kV AC transmission lines from the Switchyard to the Mona Switchyard in the vicinity of Mona, Utah, and a 144-mile, 230-kV AC transmission line from the Switchyard to the Gonder Switchyard 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.”

Thirty-five utilities (collectively, the “IPP Purchasers”) purchase the Generation Station’s output. The IPP Purchasers include the City, and the California cities of Los Angeles, Riverside, Burbank, Glendale and Pasadena (the “IPP California Participants”); 23 members of IPA (collectively, the “Utah Municipal Purchasers”); and six rural electric cooperatives serving loads in the States of Utah, Arizona, Colorado, Nevada and Wyoming (collectively, the “Cooperative Purchasers”). Pursuant to a construction management and operation agreement between IPA and the Los Angeles Department of Water and Power (“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.

The City contracted with IPA to purchase a 236 MW (13.2259%) entitlement in the capacity of the IPP plant through mid-2027. This contract obligates the City to pay in proportion to its entitlement share the costs of producing and delivering electricity (including debt service and other fixed expenses) as a cost of purchased capacity, regardless of the amount of energy scheduled to the City.

In the Fiscal Year ended June 30, 2024, the Intermountain Generating Station operated at a net plant capacity factor of approximately 26.22%. In the Fiscal Year ended June 30, 2025, the Intermountain Generating Station operated at a net plant capacity factor of approximately 60%.

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.

LADWP, as operator of the facility, has operational flexibility with respect to its use of IPP; however, the supply chain issues referenced above and the transition period to IPP's natural gas units will limit coal operations of IPP and may constrain LADWP's ability to utilize such resource until the repowering project is operational.

The Southern Transmission System provides transmission of IPP's output to the City and the other IPP California Participants. The City and SCPPA have entered into a transmission service contract to provide for transmission of the City's entitlement between the Generation Station and Adelanto. See "– Transmission Resources – Southern Transmission System" below. Transmission service from Adelanto to the City is provided under transmission service agreements with LADWP and transmission service under the CAISO tariff.

The current power purchase agreements with IPA are in effect until mid-2027. IPP's operations are affected by California 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 that restriction and as a result of strategic discussions concerning the existing contracts' expiration, IPA developed a plan to convert the coal-fired facility to a combined-cycle natural gas-fired resource. In order to facilitate the continued participation of the IPP California Participants, the IPA Board and the IPP Participants, including the City, executed individual Second Amendatory Power Sales Contracts that allow the plant to replace the coal units with combined-cycle natural gas units before 2027. The City will exit IPP upon the expiration of the current power purchase agreement in mid-2027, and does not expect to incur material costs associated with the construction of the proposed natural gas-fired units beyond 2027. Pursuant to the Second Amendatory Power Sales Contract, to the extent the existing coal units are replaced with natural gas-fired units as proposed, the City will not be responsible for future decommissioning costs associated with the IPP when the power purchase agreement expires in mid-2027. In the event that financing of the proposed natural gas-fired renewal project is not undertaken as currently proposed, the allocation of decommissioning costs to IPP Purchasers (including the City) may vary depending on the date the IPP is ultimately retired from service, what alternative project or use, if any, is instituted at the site, the level and type of remediation and/or restoration undertaken or required, and the financing options and amortization schedule for decommissioning costs.

The Utah Legislature enacted Utah Senate Bill 161 ("Utah S.B. 161") in its 2024 General Session, which became effective on May 1, 2024. The reported purpose of Utah S.B. 161 was to induce IPA to amend IPA's environmental permits to provide for the operation of at least one of the IPP coal-fired units after July 1, 2025, the date by which IPA has committed to cease operation of the IPP coal units permanently. Utah S.B. 161 also required IPA to grant an option to the State of Utah for the purchase of at least one of the IPP coal-fired units with such option to be effective for two years starting on July 2, 2025. Following the enactment of Utah S.B. 161, the governor of Utah called a special session of the Utah Legislature resulting in the enactment of Utah House Bill 3004 ("Utah H.B. 3004"), which became effective on June 21, 2024. Utah H.B. 3004 repealed the provisions of Utah S.B. 161 relating to IPA amending its environmental permits. IPA continues, however, to be obligated to provide the purchase option to the State with respect to one of the IPP coal-fired units. Utah H.B. 3004 also directs a state agency, the Decommissioned Asset Disposition Authority (the "Utah Disposition Authority"), to submit an application to amend IPA's air permit to allow for a coal unit to operate after July 1, 2025. Utah H.B. 3004 also directs environmental regulators in the State of Utah to determine whether such an application would be granted if submitted by IPA. The Utah Disposition Authority has also been directed to determine the regulatory and commercial feasibility of operating an IPP coal unit after July 1, 2025, and to conduct a process for soliciting bids from qualified purchasers for the coal unit.

Prior to the enactment of H.B. 3004, IPA stated that Utah S.B. 161 purported to create obligations for IPA that are inconsistent with IPA's obligations under federal regulations and the IPP construction and operating permits issued under federal law; and that if IPA complied with Utah S.B. 161, as originally

enacted, IPA may be subject to enforcement actions that could result in IPA being required to cease operation of the IPP coal units prior to the scheduled commercial operation date of the IPP repowering project and that may interfere with the construction and operation of the IPP repowering project. In public testimony with respect to Utah H.B. 3004, IPA management stated that the new bill made some important adjustments to the legislation and moved things in the right direction. IPA has indicated that it is still working to determine the impact of Utah S.B. 161, as modified by Utah H.B. 3004, and to identify the appropriate course of action in response to the recent enactments.

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.

The City cannot predict the ultimate impacts of the new legislation on the operation of IPP or on the construction and operation of the IPP repowering project. With respect to the status of the repowering project, the new generation facilities were previously anticipated to enter service in summer 2025. However, the repowering units were delayed until fall. Unit 3 entered commercial operation on October 10, 2025. Unit 4 entered commercial operation on December 9, 2025.

Hoover Uprating Project. The Hoover Uprating Project consists primarily of the uprating of the 17 generating units at Hoover Dam’s hydroelectric power plant, located approximately 25 miles from Las Vegas, Nevada. The City’s entitlement in the Hoover Uprating Project was approximately 40 MW. A portion of the City’s Hoover entitlement became available in June 1987 and the full entitlement became available in June 1993. The Hoover Uprating Project was substantially completed on September 30, 1995. The City originally assigned its entitlement to capacity and energy of the Hoover Uprating Project to SCPPA (in return for which SCPPA financed the advancement of funds to the United States Bureau of Reclamation for costs of the Hoover Uprating Project) and executed a power sales contract with SCPPA under which the City agreed to make monthly payments on a “take-or-pay” basis for its share of SCPPA’s proportionate share of Hoover capacity and allocated energy. These agreements expired on September 30, 2017.

The City renegotiated and executed replacement agreements directly with the Western Area Power Administration (“Western”) and the United States Bureau of Reclamation, which became effective on October 1, 2017 and extend until September 30, 2067. The City’s entitlement under the new agreements remains at approximately 40 MW. Western delivers the City’s entitlement at the Mead Substation.

Magnolia Power Project. The Magnolia Power Project is a natural gas-fired, combined cycle electric generating unit with a nominally rated net capacity of 242 MW and auxiliary facilities located in Burbank, California. The Magnolia Power Project is owned by SCPPA and is operated by the City of Burbank electric utility. The Magnolia Power Project was placed in service in September 2005 and operates in a base-load mode (8,000 hours per year or more) with staffing on a 24-hour basis. The City acquired a 38% (92 MW base capacity and 26 MW peaking capacity) entitlement in the project through a long-term power purchase agreement with SCPPA. Under its power sales agreement with SCPPA, the City is obligated to pay, on a “take-or-pay” basis, its share of the costs of the Magnolia Power Project (including operating and maintenance costs and the costs of debt service on bonds issued by SCPPA for the project) as an operating expense of the Electric System.

Canyon Power Project. The Canyon Power Project consists of a simple cycle, natural gas-fired power generating plant comprised of four General Electric LM 6000PC Sprint combustion turbines, with a combined nominally rated net peaking capacity of 200 MW, and auxiliary facilities located on approximately 10 acres of land within an industrial area of the City. The Project is owned by SCPPA and operated and maintained by the City. The Canyon Power Project was constructed for the primary purpose of providing the City with firm capacity and energy to meet its current and future capacity and energy requirements and to satisfy certain ancillary services requirements. The Canyon Power Project achieved full commercial operation in 2011. The City entered into a power sales agreement with SCPPA pursuant to which the City acquired an entitlement to 100% of the capacity and energy of the Canyon Power Project and is obligated to pay, on a “take-or-pay” basis, 100% of the costs of the project, including all operating and maintenance costs and the costs of debt service on bonds issued by SCPPA in connection with the Canyon Power Project as an operating expense of the Electric System.

The Canyon Power Project is subject to the New Source Review (“NSR”) air quality permitting program promulgated by the Southern California Air Quality Management District (“SCAQMD”), the agency responsible for developing and enforcing air quality requirements in the South Coast Air Basin (the “Basin”), which includes Los Angeles, Riverside, San Bernardino and Orange Counties. The SCAQMD’s NSR program is required to comply with certain provisions and requirements established pursuant to federal and State law, including the federal Clean Air Act. The federal Clean Air Act sets standards for different types of air pollutants and allows states to create plans to address pollution in areas with unclean air. These programs may include emission offset trading programs that require new sources to obtain emission reduction credits (“ERCs”) for every pound of new pollution that they propose to emit.

On June 21, 2024, Canyon Power Plant Unit 1 experienced a significant mechanical failure while in full operation. The unit suffered a compressor stall when one of the compressor blades broke off from the rotor, damaging all blades within the compressor. The unit is currently undergoing repairs at TransCanada Turbines in Canada. Because of industrywide shortages of gas turbine parts, the City anticipates completing repairs by early 2026. The cost of such repairs is estimated at approximately \$8 million, reflecting replacement parts, shipping, labor costs for tear-down, and inspection and analysis. Factoring in lost wholesale revenue but reduced fuel expenses, the City estimates a \$2.26 million dollar reduction in net revenue.

The June 2024 incident appears related to a known issue with GE turbines. GE issued a service bulletin recommending the replacement of Stage 3 through Stage 5 blades after 1,500 starts. However, Canyon Unit 1 experienced failure at approximately 1,000 starts, indicating an immediate need to implement this service bulletin across all units. Although all other units are below the critical threshold for starts, the City performed proactive maintenance to mitigate the risk of similar failures—ordering three sets of replacement blades and installing them on Units 2 and 4 in January 2025, at a total cost of approximately

\$242,000. The City will place the third set of blades into storage for future scheduled maintenance on the remaining units.

On December 12, 2024, the City discovered a cracked turbine blade on Canyon Power Plant Unit 3 during a bi-annual borescope inspection. Following the inspection, the City placed this unit out of service for repair. The cost to repair the unit was approximately \$3.1 million, and reduced net revenue by approximately \$157,765, reflecting lost wholesale revenue but reduced fuel expenditures. Canyon Unit 3 repairs were completed in August 2025, and the unit returned to service on August 27, 2025.

Additionally, the failure of Canyon Unit 1 and Unit 3 impacts APU's generation capacity and poses a resource adequacy constraint. To address resource adequacy, APU has procured 227 MW due to the Unit 1 outage and anticipates procuring an additional 194 MW for Unit 3, with the average cost of total procurement estimated at \$33/kW-month to meet resource adequacy requirements through the duration of the outages.

Participation of Other Parties in Generation Resources

Each of the projects (other than the Canyon Power Project and the Hoover Upgrading Project described above under “– Non-City Owned Resources”) is 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 will ultimately have a right to the capability or output of the defaulting party's share of the project. See also “Indebtedness; Joint Powers Agency Obligations” below.

Renewable Energy Resources

Consistent with State legislation, the City first adopted a Renewables Portfolio Standard (“RPS”) on December 16, 2011 that set a target of increasing its purchases of eligible renewable energy resources to 33% within three multi-year compliance periods through 2020. Since the adoption of the City's first RPS, Senate Bill 350, the Clean Energy and Pollution Reduction Act of 2015, signed into law in October 2015, increased the statewide RPS targets to 40% by December 31, 2024, 45% by December 31, 2027, and 50% by December 31, 2030. Senate Bill 100, the 100 Percent Clean Energy Act of 2018, signed into law by the Governor on September 10, 2018, further increased statewide RPS targets by requiring retail electric sellers and local publicly-owned electric utilities, such as the City, to procure a minimum quantity of electricity products from eligible renewable energy resources so that the total kWhs of those products sold to retail end-use customers achieve 44% of retail sales by December 31, 2024, 52% of retail sales by December 31, 2027 and 60% of retail sales by December 31, 2030. Senate Bill 100 established the policy of the State that eligible renewable energy resources and zero-carbon resources supply 100% of retail sales of electricity to California end-use customers by December 31, 2045. The City met all RPS compliance targets for Compliance Period 1 (covering calendar years 2011 through 2013), Compliance Period 2 (covering calendar years 2014 through 2016), and Compliance Period 3 (covering calendar years 2017 through 2020). The City anticipates meeting RPS requirements for Compliance Period 4, covering calendar years 2021 through 2024, and awaits the California Energy Commission's determination of that result.

The City's current renewable energy resources are described below. As a component of the Electric System rates and charges, the City implemented an Environmental Mitigation Adjustment which provides a mechanism for the recovery of the marginal cost differential between the utility's renewable power supply and its traditional carbon-based power supply that are not otherwise recovered in its rates. See “Electric Rates and Charges” below.

PPM Wind Contracts. The City purchased 32 MW of wind generated energy from PPM Energy under two separate contracts. Wind energy typically comes with a 33% load factor, so the PPM Energy contracts effectively represent 12 MW of resources. The first contract provides for delivery of 2 MW of energy 24 hours-a-day at a fixed price of \$53.50 per MWh over the 20-year term of the contract, which began July 1, 2004. The second contract provides 30 MW (effectively 10 MW) at a fixed price of \$55 per MWh over the 20-year term of the contract, which began July 1, 2005. The City receives energy under this contract over the Northern Transmission System at the Mona interconnection tie in the LADWP control area. The City pays for energy only when the units are operating. The 2 MW contract expired December 31, 2023, but the remaining 30 MW contract remains in place.

Brea Landfill Contracts. The City executed two power purchase agreements with Brea Power Partners, LP to deliver landfill gas renewable energy. The first short-term contract was for 5 MW with a start date of April 1, 2007 (with power received commencing July 9, 2007) from an existing facility at the Olinda Landfill through (i) the commercial operation date of a second unit or (ii) December 31, 2013. The price for energy from the Olinda Landfill project remained at \$69.00 per MWh through December 31, 2008 and then increased to \$71.00 per MWh on January 1, 2009, with an annual price escalation thereafter of 2% commencing January 1, 2010. In November 2012, a second long-term contract superseding the original contract was executed, which provides for a total of 27 MW from the new unit at the Olinda Landfill project upon commercial operation of the second unit, which occurred in November 2012. The contract for 27 MW expires October 31, 2045. The price is \$112.50 per MWh with no escalation over the term of the contract. See “ - Future Power Supply; Cost of Power and Non-Firm Power - Clean Energy Project” below.

Raser Geothermal Contract (Cyrq Energy). The City executed a power purchase agreement with a Raser Technologies subsidiary corporation for energy from an 11 MW geothermal project located in central Utah, at an initial cost of \$78 per MWh with a 2% annual escalation factor for a 20-year term that expires on September 30, 2033. The energy is delivered to the City over the Northern Transmission System at the Mona interconnection tie in the LADWP control area, at an additional transmission cost of \$2.98 per MWh. The project began commercial operation in April 2009. On or about April 29, 2011, Raser Technologies, Inc. and its Affiliated Debtors filed voluntary petitions for relief under the Bankruptcy Code. On August 30, 2011, the Bankruptcy Court confirmed the Third Amended Plan of Raser Technologies, Inc. and its Affiliated Debtors with a Plan effective date of September 9, 2011. Raser Technologies changed its name to Cyrq Energy, Inc. The Bankruptcy Court approved the reorganized subsidiary corporation’s assumption of its power purchase agreement with the City. Upon the completion of a generator upgrade on November 1, 2013, an amendment to the power purchase agreement was entered into by the City with the new Cyrq Energy subsidiary to include the Ormat Energy Converter with a nameplate capacity of 14,000 gross kW. The amended agreement provides for up to 11 MW of energy for a 20-year term, expiring in 2033, with an energy cost of \$98.50 per MWh and a 2% annual escalation factor, and transmission costs of \$3.13 per MWh.

San Gorgonio Wind Contract. The City executed a power purchase agreement with San Gorgonio Farms, Inc. for 31 MW of wind energy from the existing San Gorgonio Farms Wind Farm located in Whitewater, California. This facility reached commercial operation in 1983 and was originally under contract to Edison. The price for power is split between the environmental attributes and energy. Environmental attributes are priced at \$38.50 per MWh with no escalation and the energy price equals the revenue paid by the CAISO for delivery of the project’s energy less all CAISO charges, fees, debits, costs, penalties, and interest assigned to the project. In April 2023, the City approved an amendment to the agreement with San Gorgonio Farms, Inc. resulting in an updated price of \$22 per MWh and an extension to the term through December 31, 2033.

Bowerman Power Landfill Contract. The City executed a power purchase agreement with Bowerman Power, LLC for the purchase of 19.6 MW of energy generated from landfill gas from the Frank R. Bowerman Landfill in Irvine, California. Commercial operations began on April 27, 2016. The term of

the agreement is 20 years, expiring on April 30, 2036. The generating facility is expected to produce 154 GWh annually. The annual total cost for the renewable energy and RECs is approximately \$13.5 million with a 2.5% escalator during the first 10 years, 1.5% for the next five years, and no escalator thereafter. The initial price (during the first year) under the agreement amounts to \$87.40 per MWh less all CAISO charges, fees, debits, costs, penalties, and interest assigned to the project. See “ - Future Power Supply; Cost of Power and Non-Firm Power - Clean Energy Project” below.

Westside Assets Solar Contract. The City executed a power purchase agreement with Westside Assets, LLC for 2 MW of solar energy in Kings County, California. On December 23, 2014, an amendment to the agreement clarified language and allowed for a revision to the construction schedule. This project reached commercial operation on May 9, 2016. The agreement term began in May 2016 and lasts for 25 years, expiring on June 30, 2041. Power under the agreement is priced at \$91.00 per MWh fixed for the term less all CAISO charges, fees, debits, costs, penalties, and interest assigned to the project.

ARP-Loyalton Biomass Project. Through SCPPA, the City contracted for the purchase of 0.81 MW of energy from the 18 MW Loyalton Biomass Project over a five-year term. American Renewable Power owned and operated the project, located in the City of Loyalton, in Sierra County, California. The project reached commercial operation on April 20, 2018. Under the agreement, the City received its proportionate share of the energy output, capacity, and associated environmental attributes from the project at an estimated cost of \$638,000 per year. The agreement assisted the City towards its compliance with Senate Bill 859, passed in 2016, which requires local publicly-owned electric utilities in California that serve more than 100,000 customers to procure a proportionate share of a cumulative total of 125 MW of electric generating capacity fueled from high hazard forest materials.

Calendar year 2020 marked the last year that the City received power from the Loyalton Biomass Project. In February 2020, the operator of the project, ARP-Loyalton Cogen LLC, and its parent company American Renewable Power LLC, filed petitions for relief under Chapter 11 of the Bankruptcy Code. Under a 2024 settlement approved by the Court, proceeds of certain letters of credit were returned to the Chapter 7 trustee after deducting the amounts due to SCPPA and its participants under the power purchase agreement and SCPPA was released from, among other things, any further obligations under the agreement. The power purchase agreement has also expired under its terms.

Desert Harvest II Solar Project. Through SCPPA, the City has contracted for the purchase of 36 MW of energy from the 70 MW Desert Harvest II Solar Facility, owned by Desert Harvest II, LLC and operated by EDF Renewable Services, Inc. and located near the town of Desert Center in Riverside County, California. The project reached commercial operation on December 17, 2020. The term of the agreement is twenty-five years. Under the agreement, the City receives its proportionate share of the facility energy output and associated environmental attributes from the project at an estimated cost of \$1,851,000 per year.

Haypress Hydroelectric Contract. The City has contracted with EIF Haypress for 12.5 MW of hydroelectricity from 2 small power plants located in Sierra County, California. The plants operate as run-of-river hydro and as such, energy under the contract is “as available,” similar to wind. Power deliveries began January 1, 2024, at a price of \$60 per MWh with an annual escalator of 2.5% beginning in the second contract year. The contract expires on December 31, 2039.

Distributed Generation; Net Metering

The City’s Net Energy Metering (“NEM”) Program includes 43.9 MW of participating solar capacity installed to date, which represents 7.4% of the Electric System’s peak aggregated load. Under the City’s NEM Program, customers are able to receive either the full retail value credit shown in energy on their bill or cash compensation for the excess energy their system generates based on the City’s avoided cost of renewable electricity. The City’s NEM program includes a legislative goal of 29.6 MW, 5% of the

City's peak aggregated load, which was reached in May 2019. On January 1, 2021, the City launched its successor Net Energy Metering (NEM) Program, known as NEM 2.0, which continues to compensate customers for excess energy supplied from their distributed energy resources. Unlike the prior program, however, NEM 2.0 adjusts compensation based on the time of day, season, and market conditions, aligning payments more closely with the actual value of energy on the wholesale market.

Future Power Supply; Cost of Power and Non-Firm Power

As described above, the City currently has several contracts for firm purchases of power. These contracts accounted for approximately 81% of the City's total energy resources in the Fiscal Year ended June 30, 2025. In addition, the City can replace some of the energy otherwise available from its firm resources with energy purchased from other suppliers throughout the West. These short-term purchases are made under the Western Systems Power Pool Agreement and under bilateral agreements between the City and various suppliers. The City does this when the delivered cost of such energy is less than the variable cost of energy from its long-term resources or when additional energy is needed to meet the City's load. In the Fiscal Year ended June 30, 2025, the City purchased 595 GWh of short-term energy (about 19% of its total energy).

With the City's executed and planned divestiture of its interests in coal facilities, SJGS in 2017 and IPP expected in 2027, and the retirement of its Kraemer CT Plant at the end of 2019, the need for additional energy and capacity will be mostly offset by renewable resources as a result of California's Senate Bill 100 RPS legislation, requiring 60% of retail sales to be derived directly from renewable energy by 2030. The amount of capacity required to ensure the City's energy needs are met in the future, and to optimize its resource portfolio, will be met largely by short- and mid-term bilateral agreements. These types of agreements will provide the City with added flexibility to better manage its Electric System resource portfolio as its load profile changes over time.

The City anticipates fulfilling its customers' energy needs through dispatching power from generating plants in which it has acquired (or may in the future acquire) an ownership share, from power sales agreements, or from short-term (monthly, weekly, daily or hourly) purchases it makes on the spot market. The cost of obtaining the necessary energy will depend upon contract requirements and the current market price for energy. Spot market prices are dependent upon such factors as the availability of generating resources in the region and weather conditions such as ambient temperatures and the amount of rainfall or snowfall. Generating unit outages, dry weather, hot or cold temperatures and time of year can all adversely impact the supply and price of energy. There is no assurance that low cost energy will be available to the City in the future, though as a participant in the Western Systems Power Pool the City will have access to market priced power. The City currently has no authority to hedge pricing for either electricity or fuel utilizing financial products. However, given that the City is fully resourced to meet its retail obligations, the amount of energy procured through market mechanisms is restricted to short durations, exclusively transacted on a spot market basis where the risk exposure for price variances is limited and can be remedied almost immediately. With respect to fuel, as described under "Fuel Supply" below, the City has procured a number of resources for long-term supplies for a portion of the natural gas requirements for the Electric System that act as a hedge against short-term price variances by providing a guaranteed supply source with a fixed known price.

Clean Energy Project. On May 20, 2024, the City entered into an electricity supply agreement with SCPPA (the "Clean Energy Purchase Contract") for the purchase of renewable energy and related attributes pursuant to SCPPA's Clean Energy Project, which is structured to assist the City with obtaining a long-term supply of power at favorable prices. Under the Clean Energy Project, SCPPA issued its \$592,270,000 Southern California Public Power Authority Clean Energy Project Revenue Bonds, Series 2024A to finance the prepayment of approximately thirty years of electricity deliveries, which SCPPA will sell to the City over the term of such deliveries, in amounts and at prices as set forth in the Clean Energy

Purchase Contract. The total quantity of prepaid electricity expected to be delivered during the initial delivery period, which commenced on October 1, 2024 and ends on August 31, 2030 or upon earlier termination of the Clean Energy Purchase Contract, is an estimated 1.9 million MWh of electricity. The electricity that SCPA will be selling to the City during the initial delivery period will be obtained through the assignment of two existing power purchase agreements of the City: a Renewable Power Purchase and Sale Agreement, between the City and Bowerman Power LFG, LLC, executed by the City in March 2014, and a Consolidated, Amended, and Restated Power Purchase Agreement, dated as of December 15, 2009, among the City, Brea Power Partners, L.P. and Brea Power II, LLC. The City is the only participant in the Clean Energy Project, and the City's payment obligations under the Clean Energy Purchase Contract are payable only for electricity actually received thereunder, solely from Electric System revenues.

Roadhouse Energy Storage Project. In May 2024, the City executed a contract with Roadhouse Energy Storage, LLC, a subsidiary of NextEra Energy Resources, LLC, to design, construct, own, operate, and maintain a 300 MW battery energy storage system and sell to the City the project's energy capacity, resource adequacy, and associated attributes over a twenty-year delivery term. The project will be located on twenty acres of private land in an industrial area in Ontario, California, and requires the developer to meet performance guarantees, through augmenting the batteries as needed, for sufficient capacity and availability over the entire term. Additionally, the project qualifies as a local capacity resource given its location in the eastern Los Angeles Basin and has deliverability status with the CAISO. The City also retains operational flexibility to dispatch the battery system when needed but is not responsible for decommissioning the system following the end of the contract term. The contract is structured at a flat price of \$18.76 per kW-month with no escalation. The City anticipates that the project will commence commercial operation in mid-2027 and enhance operational flexibility and integration of renewable energy.

Fuel Supply

The SCPA Magnolia Power Project and Canyon Power Project are primarily fueled by natural gas. The City is a participant in SCPA's Natural Gas Reserves Project and SCPA's Prepaid Natural Gas Project, which provide the City with approximately 2,150 MMBtu of natural gas daily, or approximately 19% of the City's average daily baseload natural gas consumption. The remaining 81% of the City's average daily baseload natural gas consumption comes from short to medium term contracts (from one to ten years) and daily or monthly spot purchases.

Natural Gas Reserves Project. Through its participation in the SCPA Natural Gas Reserves Project, the City has joined several members of SCPA in acquiring natural gas reserves as a source of long-term supply of gas at a levelized price to provide fuel for the Magnolia Power Project. As a base-load combined-cycle facility, the City's share of fuel requirements for operating the Magnolia Power Project amounts to approximately 4.5 billion cubic feet of natural gas per year. Part of the City's overall natural gas portfolio strategy is to provide a portion of that natural gas through long-term, fixed price, gas supplies, either through long-term gas supply contracts or gas reserve field acquisitions. The SCPA Natural Gas Reserves Project includes SCPA's leasehold interests in (i) certain natural gas resources, reserves, fields, wells and related facilities located near Pinedale, Wyoming (the "Wyoming Subproject") and (ii) certain natural gas resources, reserves, fields, wells and related facilities in (or near) the Barnett Shale geological formation in Texas (the "Texas Subproject"). On June 7, 2005, the City entered into a gas sales agreement with SCPA pursuant to which the City purchased on a "take-or-pay" basis its entitlement share of the production capacity of the related leasehold interests in the gas reserve fields and related facilities. Pursuant to the gas sales agreement, the City's entitlement share in the Wyoming Subproject was acquired at a cost of approximately \$16.4 million. The City has taken delivery of this gas since July 2005. The City's entitlement share in the Texas Subproject, which was subsequently acquired at a cost of approximately \$18.6 million, also aids in supplying the City's gas needs for the Magnolia Power Project. The City's gas sales agreement with SCPA for both the Wyoming Subproject and Texas Subproject expires in 2032. On February 6, 2008, SCPA issued revenue bonds for the benefit of the City and two of the other Natural Gas

Reserves Project participants in simultaneous financings in order to finance their respective shares of the acquisition costs of the Natural Gas Reserves Project.

Prepaid Natural Gas Project. The City 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 other gas-fired generation stations. In connection with the prepaid natural gas financing, the City purchases on a “take-and-pay” basis natural gas acquired by SCPPA pursuant to the terms of a prepaid natural gas sales agreement between SCPPA and J. Aron & Company (“J. Aron”) at a discount from the spot price over a term of approximately 27 years (as a result of restructuring as described below) beginning on July 1, 2008. On October 22, 2009, the Prepaid Natural Gas Sales Agreements between SCPPA and J. Aron were restructured to provide an acceleration of a portion of the long-term savings, reduce the remaining volumes of gas to be delivered and shorten the overall duration of the agreements. As a result of the restructuring, a portion of the bonds issued by SCPPA with respect to the Prepaid Natural Gas Project was discharged. On September 19, 2013, the transaction was further restructured, as a result of which approximately \$561,000 was remitted to the City from a lump sum payment received by SCPPA from the gas supplier. The City’s restructured natural gas supply agreement with SCPPA is expected to provide approximately 13% of the City’s historical gas requirements for the Magnolia Power Project.

Renewable Biomethane. The City executed a renewable Biomethane Purchase and Sale Agreement with SoCal Biomethane (the “Biomethane Agreement”), a subsidiary of Anaergia, Inc., to purchase renewable biomethane derived from food waste, which has been diverted from landfills to a digestions and gas production facility outside of the City. The Biomethane Agreement was assigned from SoCal Biomethane to Rialto Bioenergy Facility, LLC (“RBF”) pursuant to the Assignment and Assumption Agreement dated November 13, 2018, by and among SoCal Biomethane, RBF, and the City. The renewable Biomethane Agreement provides for the purchase of up to 210,240 MMBtu per year at an initial price of \$12.74/MMBtu starting in the Fiscal Year ending June 30, 2021, which escalates annually by an average of 1.4% over the 20-year term of the agreement. The City terminated the Biomethane Agreement effective November 2, 2022. The City determined that RBF could not meet their contractual obligations, as a lack of sufficient feedstock hindered production and delivery of biomethane.

Transmission Resources

Southern Transmission System. The City is a participant in SCPPA’s Southern Transmission Project. The Southern Transmission System (“STS”) is an approximately 490-mile, ±500-kV DC transmission line that extends from IPP near Delta, Utah to the Adelanto Substation in Southern California, together with an AC/DC converter station at each end of the transmission line. The STS is owned by IPA and is one of three major components of IPP. LADWP operates and maintains the STS under contract with IPA. In connection with its entitlement to IPP, the City assigned its entitlement to capacity of the STS to SCPPA, in exchange for which SCPPA agreed to make payments-in-aid of construction of the STS and issued revenue bonds to finance the costs thereof. Pursuant to a transmission service contract with SCPPA, the City acquired a contractual entitlement to 17.647% of the transfer capability of the STS which obligates the City to pay the costs of its share of the transfer capability (including operating costs and debt service costs on bonds issued by SCPPA for the project) on a “take-or-pay” basis as an operating expense of the Electric System. The transfer capability of the STS is currently approximately 2,400 MW (as a result of upgrades completed in December 2010). The City’s entitlement in SCPPA’s share of the transfer capability of the STS is approximately 423.5 MW. The City’s contractual entitlement and obligation extends until 2027, consistent with the timeframe of the current power purchase agreements with IPA. See “Power Supply Resources – Non-City Owned Resources - Intermountain Power Project” above.

Mead-Adelanto Project, Authority Interest (Multiple Members). The City is a participant in SCPPA’s member-related interest in the Mead-Adelanto Project. The City entered into a transmission service contract with SCPPA that provides the City with an entitlement share (approximately 118 MW) of

SCPPA's member-related ownership interest (the "Authority Interest (Multiple Members)") in the Mead-Adelanto Project and obligates the City to pay for its share of the costs of SCPPA's Authority Interest (Members) in the Mead-Adelanto Project (including operating costs and debt service costs on bonds issued by SCPPA for the project) on a "take-or-pay" basis as an operating expense of the Electric System. The City's entitlement share is 9.1666% of SCPPA's 67.9167% Authority Interest (Multiple Members) in the project. The City's transmission service agreement with SCPPA for the Mead-Phoenix Project runs through October 31, 2030. The City uses the Mead-Adelanto Project for the transmission of energy purchased by the City.

Mead-Phoenix Project, Authority Interest (Multiple Members). The City is a participant in SCPPA's member-related interest in the Mead-Phoenix Project. The Mead-Phoenix Project is an approximately 256-mile, 500-kV AC transmission line that extends from the Westwing Substation (in the vicinity of Phoenix, Arizona), connects with the Mead substation near Boulder City, Nevada and terminates at the Marketplace Substation nearby. SCPPA executed an ownership agreement providing it with an 18.3077% member-related ownership share in the Westwing-Mead project component, a 17.7563% member-related ownership share in the Mead Substation project component, and a 22.4082% member-related ownership share in the Mead-Marketplace project component (collectively, the "Authority Interest (Multiple Members)") in the Mead-Phoenix Project. The Mead-Phoenix Project has an estimated transfer capability of 1,923 MW (as a result of certain upgrades completed in 2009). The City entered into a transmission service contract with SCPPA that provides the City with an entitlement to approximately 47 MW of transfer capability of the Mead-Phoenix Project and obligates the City to pay for its share (approximately 24.2%) of the costs of SCPPA's Authority Interest (Members) in the Mead-Phoenix Project (including operating costs and debt service costs on bonds issued by SCPPA for the project) on a "take-or-pay" basis as an operating expense of the Electric System. The City's entitlement shares in the three components of the Mead-Phoenix Project are as follows: 3.615% of the Westwing-Mead project component, 8.8781% of the Mead Substation project component and 5.9395% of the Mead-Marketplace project component, respectively, of the Authority Interest (Multiple Members) in the project. The City's transmission service agreement with SCPPA for the Mead-Phoenix Project runs through October 31, 2030. The City uses the Mead-Phoenix Project for the transmission of energy purchased by the City.

Anaheim's CAISO Arrangements

The CAISO began operations on March 31, 1998. The fundamental purpose of the CAISO is to operate the transmission system in a manner that is independent of the interests of the owners of the transmission facilities to buy or sell energy. The CAISO provides transmission service and related ancillary services to all users, including the City, on a non-discriminatory basis.

In June 2002, the City notified the CAISO of its intent to become a Participating Transmission Owner ("PTO") by turning over operational control of the City's transmission entitlements. In November 2002, the City executed the Transmission Control Agreement between the CAISO and the PTOs. On January 1, 2003, the City became a PTO under the CAISO tariff by turning over operational control of its transmission entitlements to the CAISO. In return, the City receives payment of its revenue requirement for such facilities from the CAISO. The City now obtains all of its transmission scheduling requirements from the CAISO, and it procures additional required ancillary services from the CAISO or from the open competitive market. On May 1, 2020, APU submitted a proposal to the Federal Energy Regulatory Commission ("FERC") to revise its transmission revenue requirement. Effective July 1, 2020, FERC issued an order accepting APU's proposed transmission revenue requirement.

Customers and Energy Sales

The Electric System serves the entire area within the City limits (an area of approximately 50 square miles) as well as small portions of unincorporated Orange County adjacent to the City. Tables 4 and 5 below set forth the average number of customers and total electrical energy sold (in GWh) during the five fiscal years shown.

**TABLE 4
AVERAGE NUMBER OF CUSTOMERS⁽¹⁾**

	Fiscal Year Ended June 30,				
	2025	2024	2023	2022	2021
Residential	107,148	105,839	105,422	104,561	103,666
Commercial	17,541	17,498	17,500	17,557	17,466
Industrial.....	264	269	290	273	271
Other	101	109	110	112	112
Other Utilities	<u>11</u>	<u>11</u>	<u>11</u>	<u>11</u>	<u>11</u>
Total – All Classes	<u>125,065</u>	<u>123,726</u>	<u>123,333</u>	<u>122,514</u>	<u>121,526</u>

⁽¹⁾ Average number of meters as a proxy for number of customers.
Source: Anaheim.

[Remainder of page intentionally left blank.]

**TABLE 5
TOTAL ENERGY SOLD
(GWh)**

	Fiscal Year Ended June 30,				
	2025	2024	2023	2022	2021
Residential	616	586	637	600	630
Commercial.....	732	717	731	706	660
Industrial	788	811	856	851	739
Other ⁽¹⁾	1	1	1	1	1
Other Utilities ⁽²⁾	<u>651</u>	<u>421</u>	<u>470</u>	<u>524</u>	<u>622</u>
Total – All Classes ⁽³⁾	<u>2,788</u>	<u>2,536</u>	<u>2,695</u>	<u>2,682</u>	<u>2,652</u>

⁽¹⁾ This category includes streetlights (which comprise 91% of this category) as well as outdoor lights.

⁽²⁾ Reflects wholesale sales activity under prevailing market conditions.

⁽³⁾ The difference between the total GWh generated and purchased shown in Table 3 captioned “Total Gigawatt Hours (GWh) Generated and Purchased and Peak Demand (MW)” and total energy sold as shown in this Table 5 is due to transmission and distribution system losses, wholesale transactions, and renewable energy credits (“RECs”).

Source: Anaheim.

During the Fiscal Year ended June 30, 2025, the City satisfied 100% of its power requirements for serving retail customers through a combination of long-term and short-term firm and non-firm power purchases.

Wholesale Power

From time to time, the City has the opportunity to purchase power from and sell power to a number of power marketing firms, independent power producers, and other electric utilities, and to enter into contracts for the forward purchase and sale of electricity. The City recognizes that its wholesale market activities give rise to certain risks and has committed resources to mitigate them through the establishment of a formal risk management program. Wholesale power trading optimizes the value of the utility’s assets to cost-effectively serve its retail load. The City Council approved a risk management policy (the “Policy”) to provide policy guidance with respect to its wholesale trading activities. Pursuant to the Policy, the City established a Risk Management Committee (composed of the Public Utilities General Manager, the City Finance Director, the City Attorney, the Anaheim Public Utilities Assistant General Managers of Finance & Energy Resources and Administration & Risk Services, the Integrated Resources Manager, the Financial Services Manager, and the Chief Risk Manager) to oversee the City’s Wholesale Energy Risk Management Program (the “Program”) which governs all proposed power purchase agreements, whether for retail or wholesale purposes. Pursuant to the Policy, the Program approved by the Risk Management Committee governs the various functions of the trading operations. The Policy and Program are intended to: (a) provide a common risk management infrastructure to facilitate management control and reporting; (b) create a procedure to evaluate the creditworthiness of the counterparties, and to monitor and manage the aggregate credit exposure; (c) establish a corporate culture exemplifying best practices in risk management; (d) create a mechanism to identify market-related opportunities within the City’s overall exposure balance or “book”; and (e) develop an effective, streamlined ability to timely commit to transactions. The Program establishes guidelines for, among other things, authorized transaction limits, acceptable counterparty creditworthiness standards and requirements for limits on credit exposure to any individual counterparty. Most of the City’s short-term purchase and sale transactions for wholesale power opportunities are 30 days or less.

Major Customers and Economic Conditions

APU serves a diverse customer base from a variety of industries, including tourism, hospitality, medical facility, aerospace, and telecom sectors. For the Fiscal Year ended June 30, 2025, the top 10 largest

power customers of the Electric System, in terms of kilowatt hour (“kWh”) sales, accounted for approximately 17.1% of the Electric System’s total energy sales.

A major development project occurring in Anaheim is OCVibe, a planned 95-acre development that includes new homes, shopping, dining, entertainment, hotels, office space, and parks adjacent to the Honda Center. This \$4-billion expansion proposes to add 1,500 apartments with affordable housing options; four parking structures and surface lots to add more than 11,000 parking spaces; 20 acres of publicly accessible parks, trails, plazas, and other spaces; a new 5,700-seat concert venue; more than 35 restaurants with 170,000 square feet of indoor and outdoor dining space; two new hotels collectively adding 550 rooms; 1.2 million square feet of office space; and more than 80,000 square feet of shopping options. A phased opening is planned for 2028, when the Honda Center is slated to host indoor volleyball for the 2028 Summer Olympics.

Another major project is DisneylandForward, a multiyear public planning effort to expand and update Disneyland theme parks, hotel offerings, entertainment, parking, restaurants, and more. The project proposes a \$1.9 billion plus investment in Anaheim over 10 years. It includes updating land use approvals from the 1990s to allow Disneyland Resort to build attractions or hotels on land originally designated for parking or other purposes.

Electric Rates and Charges

Description of Rates and Charges. The City is obligated by the Charter and by certain resolutions of the City Council under which it has electric revenue bonds outstanding to establish rates and collect charges in an amount sufficient to service the City’s Electric System indebtedness, to meet its expenses of operation and maintenance and to pay other obligations payable from gross revenues, with specified requirements as to priority and coverage. The City Council establishes electric rates, which are not subject to regulation by the CPUC or by any other state agency.

The rates charged by the City to its customers are also not subject to approval by any federal agency; however, the Public Utility Regulatory Policies Act (“PURPA”) requires state regulatory authorities and nonregulated electric utilities, including the City, to consider certain rate-making standards and to make certain determinations in connection therewith. The City believes that it is operating in compliance with PURPA.

The Charter requires that electric rates be based upon the cost of service to the various customer classes. As provided in Section 909 of the Charter, the City’s Public Utilities Board has the power and duty to conduct all public hearings for the electric utility, including those for the consideration of utility rates and to make recommendations to the City Council concerning electric rates adopted by the City Council.

The Anaheim Electric System has a number of base rate schedules. Generally, all costs of the Anaheim Electric System, including power supply costs, are recovered through the application of these base rates. The City’s customer rates also include a Rate Stabilization Adjustment (“RSA”) that increases or decreases specifically for the recovery of the respective fluctuations in power supply, relevant operational costs, and environmental mitigation costs to meet specified financial performance indicators and goals. The goals stated within the rate schedule include the maintenance of debt service coverage ratios no less than 1.5 times and a balance in the account for deferred inflows (RSA collections) equal to approximately \$50 million.

The RSA contains two components: the Power Cost Adjustment (“PCA”) and the Environmental Mitigation Adjustment (“EMA”). The PCA can increase up to ½¢ per kWh in any 12-month period to collect for changes in power production costs, purchased power costs, regulatory compliance costs, debt service and any other costs involved in delivering energy. Additionally, if the Electric System’s power

supply or fuel costs increase by more than 10% over originally budgeted levels for a period of one month or longer or if the Electric System loses a major resource, such as a generation or transmission unit, then the PCA may increase by an additional 1¢ per kWh over and above the current ½¢ limit until all associated costs are collected at which time the PCA will be reduced to its previous level. This provision recovered costs related to an outage at IPP. The second component of the RSA, the EMA, allows for the recovery of environmental mitigation costs, such as projected greenhouse gas emissions costs, the marginal cost differential between renewable power and traditional carbon-based power, and environmental mitigation costs imposed by regulatory bodies, legislative mandates or judicial settlements, orders or decrees. The EMA is structured similarly to the PCA in that the annual limit of the increase is ½¢ per kWh unless costs increase by more than 10% of projections, at which point the EMA's limit on annual increases may be increased by an additional 1¢ per kWh until all associated costs are collected, and at that time the EMA will be reduced to its previous level.

The RSA collections are treated as deferred inflows for accounting purposes and are used by management to mitigate material fluctuations in the cost of energy, loss of revenues or unbudgeted costs including the unexpected long-term loss of a generating facility, unplanned limits on the ability to transmit energy to the City, or disasters that could otherwise negatively affect the revenue stream. At management's discretion, amounts in the RSA accounts may be withdrawn and recognized as gross revenues of the Electric System in order to maintain sufficient debt service coverage ratios. As of June 30, 2025, the balance in the RSA regulatory credit account, after recognition of RSA revenue for the fiscal year ending on that day, was approximately \$110.0 million.

The RSA provides the City with operational and billing flexibility. With respect to any RSA adjustment, the City first considers the result on customer bills with a goal of maintaining total electric charges that are competitive with those of other utilities in the region. Any change indicated by the RSA calculation is reviewed against other known long-term factors prior to any automatic implementation of rate changes. This allows the City to blend forecasted increases or decreases in the projected power supply or operational costs to meet the financial requirements of the City and mitigate future fluctuations in electrical costs to customers. The General Manager has the authority to adjust the RSA within prescribed guidelines.

Effective May 1, 2024, the City updated its electric rate schedule, lowering certain variable rate components (such as the PCA and the EMA) with corresponding increases to base rates to better align with current costs. The PCA charge has been set to zero for all customer classes, and the EMA charge is 0.0005¢ per kWh for all customer classes. While related upward adjustments have been incorporated into the existing base rates, the PCA and EMA charges remain available as described above for potential future adjustments when needed. In addition, all classes pay an undergrounding surcharge equal to 4% of base rate charges (exclusive of RSA) in order to fund the conversion of overhead power lines into underground lines throughout the City. The City does not impose a utilities' user tax.

The City's current primary rate schedules for residential, commercial and industrial customers of the Electric System are set forth in Table 6 below.

[Remainder of page intentionally left blank.]

TABLE 6
PRIMARY RATE SCHEDULES FOR RESIDENTIAL, COMMERCIAL
AND INDUSTRIAL CUSTOMERS
(As of June 30, 2025)

Type and Description of Service

Domestic Services Single Family Customers (Basic):

Customer Charge, per meter, per month	\$ 8.00
Energy Charge (added to Customer Charge):	
First 10 kWh per day, cents per kWh	14.00
All Excess kWh, cents per kWh	21.49

General Service Small Commercial Customers:

Customer Charge, per meter, per month	\$ 24.00
Energy Charge (to be added to Customer Charge):	
All kWh, cents per kWh	19.60

General Service Medium Commercial Customers:

Customer Charge	\$ 56.00
Demand Charge (added to Customer Charge)	
First 15 kW or less of billing demand	166.00
All excess kW of billing demand per kW	17.13
Energy Charge (added to Demand Charge)	
All kWh, cents per kWh	13.78

General Service Large Commercial and Industrial Customers:

Customer Charge, per meter, per month	\$ 370.00
Demand Charge (to be added to Customer Charge):	
First 200 kW or less of billing demand	3,726.00
All excess kW of billing demand, per kW	21.10
Energy Charge (to be added to Demand Charge):	
For the first 540 kWh per kW of billing demand, cents per kWh	13.03
All excess kWh, cents per kWh	9.00

	<u>Summer</u>	<u>Winter</u>
Commercial Optional Time of Use Rate:		
Customer Charge, per meter, per month:	\$350.00	\$350.00
Demand Charge (added to Customer Charge):		
Non-Time related Maximum Demand, per kW	11.00	11.00
Plus all on-peak billing demand, per kW	19.95	N/A
Plus all mid-peak billing demand, per kW	6.98	10.93
Plus all off-peak billing demand, per kW	N/A	N/A
Energy Charge (added to Demand Charge):		
All on-peak energy, cents per kWh	17.32	N/A
Plus all mid-peak energy, cents per kWh	13.60	14.56
Plus all off-peak energy, cents per kWh	9.20	9.20

Source: Anaheim.

Average Billing Price. The table below sets forth the average billing price per kWh for the various customer classes during the five fiscal years shown (taking into account the PCA, the EMA and the 4.00% undergrounding surcharge).

**TABLE 7
AVERAGE BILLING PRICE (CENTS) PER KILOWATT-HOUR
(RETAIL SALES)**

	Fiscal Year Ended June 30,				
	<u>2025</u>	<u>2024</u>	<u>2023</u>	<u>2022</u>	<u>2021</u>
Residential	19.73	20.09	19.16	18.28	18.13
Commercial.....	21.22	21.38	19.86	19.61	19.38
Industrial.....	17.99	18.82	17.00	16.59	16.49
Other	19.17	21.23	19.44	16.70	16.63
System Averages	19.59	20.27	18.56	18.05	17.94

Source: Anaheim.

Cost Recovery and Reserves. APU’s electric rates include components that largely decouple revenues from sales and allow for the timely recovery of costs and achievement of financial goals. The City Council authorized APU to employ this rate stabilization adjustment mechanism when needed, allowing for timely cost recovery, customer bill stability, and the ability to raise approximately \$65 million per year (based on historical electricity demand) without requiring City Council action. These rate mechanisms, coupled with financial reserves (including the rate stabilization adjustment balance) equal to approximately 200 days of operating expenses and a \$100 million revolving line of credit with Wells Fargo Bank, N.A., provide APU with the means to offset potential lost revenue from reduced retail sales and/or increased costs.

[Remainder of page intentionally left blank.]

Capital Improvements Plan

As part of its capital planning process, the City identified the following Electric System capital improvement projects scheduled through the fiscal year ending June 30, 2030 (the “Five-Year Plan”), totaling approximately \$448.6 million:

	Five-Year Plan ⁽¹⁾ 2025-26 through 2029-30 (\$000)
Substation Improvements	\$ 151,169
System Undergrounding	76,152
Electric Facilities & Streetlights	64,902
Cable Replacement & System Expansion	54,859
Transmission & Distribution	47,807
Transformer Replacement	37,726
System Protection, Automation, & Telecom	<u>16,033</u>
Total	<u>\$448,649</u>

⁽¹⁾ The five-year plan shown represents projected capital expenditures only, not City Council adopted budgets. As such, figures may change based on timing of projects, related expenditures, and re-prioritization of projects.

The City’s electric capital program aims to improve electric service reliability, enhance system resiliency, improve operational efficiencies, support system growth, and integrate renewable resources. Transmission and distribution projects replace aging overhead electrical and communication facilities with new underground facilities to improve overall system reliability, public safety, and aesthetics. Projects involving the Electric System’s distribution substations include enhancements to existing substations that will improve reliability and provide sufficient flexibility and capacity for future electric load growth. System undergrounding projects place overhead electrical and communication infrastructure along Anaheim’s major thoroughfares underground, including in high fire-threat zone areas for wildfire mitigation. Electric facilities and streetlights include construction of a backup operations and field station facility and street light additions and upgrades. Cable replacement projects replace aged and deteriorated cable, utilizing more resilient conduits. The transformer replacement program replaces existing overhead transformers to reduce the likelihood of emergency repairs. System Protection and Automation includes the electric system automation, protection, and Supervisory Control and Data Acquisition (“SCADA”) upgrades to enhance the resiliency and flexibility of the electric distribution system, while telecommunication projects upgrade and expand the fiber optic infrastructure to enable automation.

The City funds its capital plan through a combination of long-term financing, pay-as-you-go, and other resources such as grants. The City assesses and utilizes the capital markets on a periodic basis to fund appropriate capital projects based on its planning models. The City currently anticipates it will finance approximately 27% of the capital costs identified in the Five-Year Plan through existing and new bond proceeds. These projections may change based on deferrals of Electric System capital improvement projects or changes in the mix of financial resources used to fund capital projects.

Insurance

The Electric System participates in the City’s self-insured workers’ compensation and general liability program. The liability for such claims, including claims incurred but not reported, is transferred to the City in consideration of self-insurance premiums paid by the Electric System. Premiums for workers’ compensation and general liability programs are charged to the Electric System by the City based on various allocation methods that include actual cost, trends in claims experience, exposure base, and number of

participants. Premiums charged and paid totaled \$4,539,000 and \$4,224,000 for the years ended June 30, 2024 and June 30, 2025, respectively.

As of June 30, 2025, the City was fully funded for self-insured workers' compensation and general liability claims (self-insured retention levels of \$2,000,000 per occurrence for workers' compensation claims and \$1,000,000 per occurrence for general liability claims). Above these self-insured retention levels, the City's potential liability is covered through various commercial insurance and intergovernmental risk pooling programs. Settled claims have not exceeded total insurance coverage in any of the past three years, nor does management believe that there are any pending claims that will exceed total insurance coverage.

The City maintains an internal services fund to account for self-funded general liability claims and certain other items (the "Insurance Fund"). The unpaid claims liability included in the Insurance Fund is based on the results of actuarial studies and includes amounts for claims incurred but not-reported, known-claim development, and allocated loss adjustment expenses. Claims liabilities are calculated using a discount rate of 2.25% and consider the effects of inflation, multiyear loss development trends, and other economic and social factors. It is the practice of the City to obtain full annual actuarial studies annually for its retained levels for general liability and workers' compensation exposures. "Premiums" are charged by the Insurance Fund to City departments, including APU, using allocation methods that include actual costs, claims experience and applicable exposure bases.

Wildfire Mitigation Measures

APU has implemented comprehensive wildfire mitigation measures to reduce the risk of utility-associated wildfires. A portion of the Electric System service area falls within geographical areas classified by the CPUC's Fire Threat Map as "Tier 2" or "Tier 3" fire-threat zones (FTZs), representing areas of elevated or extreme wildfire risk. Within the four Tier 3 FTZs in the City's boundaries, which account for 13.86% of the City, approximately 98.1% of APU-owned power lines are underground. The remaining above-ground power lines in these Tier 3 FTZs are de-energized unless required for electricity distribution, significantly reducing the risk of wildfire ignition. An additional 0.64% of the service area is identified as a Tier 2 fire-threat zone.

APU actively monitors conditions that may require de-energizing lines and has established operational protocols for immediate power shutoffs within FTZs. These protocols are documented in APU's wildfire mitigation response procedures, outlining both operational steps and communication plans.

APU's wildfire emergency preparedness strategy includes annual workforce emergency response training, flexibility to re-route power during outages and emergencies with minimal service disruption, and the ability to disable automatic reclosing of protective relays on certain transmission lines in Tier 3 FTZs during dangerous weather conditions — ensuring power is only restored after manual inspection confirms safe operation. APU coordinates closely with the City's Anaheim Fire & Rescue agency (AF&R) for structure fires and other emergencies, regardless of wildfire risk, and participates in a citywide safety committee with AF&R, and the City's police, public works, and safety agencies to address public safety concerns quarterly.

Additionally, while Edison operates 500-kV high-voltage transmission lines through the East Anaheim FTZ, APU customers are not affected by Edison's public safety power shutoffs. Anaheim relies on regional transmission service via Edison, but redundant transmission paths that bypass FTZs reduce the risk of losing service. APU and Edison conduct annual meetings to review operational and communication procedures related to wildfire mitigation.

Pursuant to California Senate Bill 901, which became law in 2018 and requires all public and private utilities to assess their geographical area of service where overhead electrical lines and equipment may pose significant wildfire risk, APU presents a wildfire mitigation plan (“WMP”) annually to its Public Utilities Board for approval and adoption. The Anaheim Public Utilities Board’s most recent approval of APU’s WMP was on June 25, 2025. Additionally, California Public Utilities Code Section 8387 requires an independent evaluation from an evaluator with expertise in electrical infrastructure safety every three years. APU’s last independent evaluation occurred in 2023, with the evaluator concluding that Anaheim’s 2023 WMP was “comprehensive” and met CPUC requirements. The next independent evaluation is scheduled for the 2026 WMP.

As part of its 2025 WMP, APU updated its Wildfire Threat Zone map to reflect the more conservative classification between CalFire’s Fire Hazard Zones issued on March 24, 2025, and CPUC’s High Fire-Threat District Map last updated in 2018. In July 2025, the City Council adopted the CalFire map, through amending various sections of the municipal code.

Transfers to the General Fund

Transfers of Electric System funds to the City’s General Fund occur on a semi-annual basis. Under the Charter, annual transfers may not exceed 4% of gross revenues of the electric utility for the prior fiscal year.

Indebtedness; Joint Powers Agency Obligations

Direct Obligations. As of June 30, 2025, in addition to its obligations under its joint powers agency contracts (see “– Joint Powers Agency Obligations” below), the City had outstanding \$579,235,000 principal amount of long-term obligations payable from Electric System revenues, consisting of installment purchase payments (“Qualified Obligations”) payable by the City under installment purchase agreements with the Anaheim Housing and Public Improvements Authority (“AHPIA”) or the California Municipal Finance Authority (“CMFA”) relating to bonds issued by AHPIA or CMFA for the benefit of the Electric System, which are payable from surplus Electric System revenues after payment of maintenance and operations expenses of the Electric System and the replenishment of certain reserves and other funds.

The outstanding Qualified Obligations are summarized in the table below.

[Remainder of page intentionally left blank.]

TABLE 8
OUTSTANDING QUALIFIED OBLIGATIONS
(as of June 30, 2025)

<u>Issue</u>	<u>Date of Installment Purchase Agreement</u>	<u>Principal Amount Outstanding</u>
California Municipal Finance Authority Revenue Refunding Bonds, Series 2014-A (City of Anaheim Electric Utility Distribution System Refunding)	10/01/14	\$ 8,825,000
California Municipal Finance Authority Revenue Refunding Bonds, Series 2015-B (City of Anaheim Electric Utility Distribution System Refunding and Improvements)	06/01/15	37,155,000
Anaheim Housing and Public Improvements Authority Revenue Refunding Bonds, Series 2017-A (Electric Utility Distribution System Refunding)	12/01/17	25,230,000
Anaheim Housing and Public Improvements Authority Revenue Bonds, Series 2020-A (Electric Utility Distribution System Improvements)	03/01/20	38,865,000
Anaheim Housing and Public Improvements Authority Revenue Refunding Bonds, Series 2020-B (Electric Utility Distribution System Refunding)	03/01/20	46,105,000
Anaheim Housing and Public Improvements Authority Revenue Refunding Bonds, Series 2020-C (Electric Utility Distribution System Refunding)	03/01/20	21,955,000
Anaheim Housing and Public Improvements Authority Revenue Bonds, Series 2022-A (Electric Utility Distribution System)	04/01/22	155,145,000
Anaheim Housing and Public Improvements Authority Revenue Bonds, Series 2022-B (Electric Utility Generation System)	04/01/22	69,065,000
Anaheim Housing and Public Improvements Authority Revenue Refunding Bonds, Series 2022-D (Electric Utility Distribution System Refunding) (Federally Taxable)	04/01/22	33,415,000
Anaheim Housing and Public Improvements Authority Revenue Refunding Bonds, Series 2022-E (Electric Utility Distribution System Refunding) (Forward Delivery)	04/01/22	34,095,000
Anaheim Housing and Public Improvements Authority Revenue Refunding Bonds, Series 2024-A (Electric Utility Distribution System Refunding)	08/20/24	<u>109,380,000</u>
Total		\$ 579,235,000

Source: Anaheim.

The City has entered into an Amended and Restated Revolving Credit Agreement, dated as of December 7, 2023 (the “Revolving Credit Agreement”) with Wells Fargo Bank, National Association (the “Credit Bank”), under which the City may borrow up to \$100,000,000 for purposes of the Electric System. The repayment obligation of the City for amounts borrowed under the Revolving Credit Agreement for the Electric System is evidenced by Electric Revenue Anticipation Notes of the City which are payable from and secured by surplus Electric System revenues on a basis that is junior and subordinate to the payment of the Qualified Obligations.

Any outstanding Electric System borrowings of the City under the Revolving Credit Agreement that have not been paid (which borrowings may be paid from, among other sources, proceeds of future long-term financings of the City) on or prior to the facility maturity date of the Revolving Credit Agreement (i.e., currently December 6, 2028, unless extended) will be automatically converted to term loans on such date, so long as no default or event of default by the City shall have occurred and be continuing and all representations and warranties of the City under the Revolving Credit Agreement are true and correct in all material respects as of such date.

The Revolving Credit Agreement is also available for Water System borrowings. Borrowings for the Water System will reduce the commitment available under the Revolving Credit Agreement by an amount corresponding to such Water System borrowing. As of August 1, 2025, there is no balance outstanding under the Revolving Credit Agreement.

Joint Powers Agency Obligations. As described herein, the City participates in or contracts with several joint powers agencies, including IPA and SCPPA. Obligations of the City under the agreements with IPA and SCPPA constitute maintenance and operation expenses of the Electric System payable prior to any of the payments required to be made with respect to the City’s outstanding direct Electric System obligations (including the Qualified Obligations and Electric Revenue Anticipation Notes). Agreements between the City and IPA and the City and SCPPA (other than the agreement relating to SCPPA’s Prepaid Natural Gas Project bonds and Clean Energy Project bonds) are on a “take-or-pay” basis, which requires payments to be made whether or not applicable projects are completed or operable, or whether output from such projects is suspended, interrupted or terminated. All of these agreements (other than the agreements relating to SCPPA’s Prepaid Natural Gas Project bonds, the Natural Gas Reserves Project bonds, the Canyon Power Project bonds and the Clean Energy Project bonds) contain “step-up” provisions obligating the City to pay a share of the obligations of a defaulting participant. The City’s participation and share of debt service obligation (without giving effect to any “step-up” provisions) for each of the joint powers agency projects in which it participates are shown in the following table.

[Remainder of page intentionally left blank.]

TABLE 9
OUTSTANDING DEBT OF JOINT POWERS AGENCIES AND ANAHEIM'S SHARE
(as of December 1, 2025)

	<u>Principal Amount of Outstanding Debt</u>	<u>Anaheim's Participation⁽¹⁾</u>	<u>Anaheim's Share of Principal Amount of Outstanding Debt⁽²⁾</u>
Intermountain Power Agency			
Intermountain Power Project.....	\$ 112,520,000	13.225%	\$ 5,385,671 ⁽³⁾
Southern California Public Power Authority			
Southern Transmission System	72,190,000	17.647	12,739,369
Magnolia Power Project ⁽⁴⁾	187,770,000	39.683	74,513,145
Prepaid Natural Gas Project ⁽⁵⁾	219,555,000	16.500	36,226,575
Natural Gas Reserves	13,300,000	100.000	13,300,000
Canyon Power Project	222,885,000	100.000	222,885,000
Clean Energy Project ⁽⁶⁾	591,720,000	100.000	591,720,000
Subtotal	<u>1,307,420,000</u>		<u>951,384,089</u>
Total	<u>\$ 1,419,940,000</u>		<u>\$ 956,769,760</u>

(1) Obligation is subject to increase upon default of another project participant (other than with respect to SCPPA's Prepaid Natural Gas Project bonds, the Natural Gas Reserves Project bonds, the Canyon Power Project bonds and the Clean Energy Project bonds).

(2) Reflects outstanding bonds and subordinated notes applicable to the City.

(3) Reflects net share of principal amount of outstanding debt after giving effect to amounts received from IPA's issuance of its Series K Notes in July 2025.

(4) Excludes bonds relating solely to City of Cerritos.

(5) Not a "take-or-pay" obligation; the City must pay for contracted natural gas only to the extent delivered.

(6) Not a "take-or-pay" obligation; the City must pay for contracted electricity only to the extent delivered.

Source: Anaheim; IPA.

For the Fiscal Year ended June 30, 2025, the City estimates that payments of debt service on its joint powers agency obligations totaled approximately \$38.6 million. Annual debt service on the City's joint powers agency obligations is expected to decrease from this level to approximately \$19.5 million in the Fiscal Year ending June 30, 2040. This projection assumes no future debt issuances and further assumes that all variable rate joint powers agency debt obligations remain hedged. Currently, all joint powers agency debt that Anaheim is a participant in is either fixed or fully-hedged if variable. 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.

Accounting Policies

The Electric System's accounting records, financial transactions and billing are computerized. The City's independent auditor performs an audit of the Electric Utility Fund of the Electric System at the same time as the other financial statements of the City are audited.

Funds of the Electric System are separated from the General Fund of the City, and the books and records are maintained separate and apart from all other funds and accounts of the City.

For further information concerning the Electric System's financial position, see the audited financial statements of the Anaheim Electric Utility Fund for the Fiscal Year ended June 30, 2025 filed on the Electronic Municipal Market Access website of the Municipal Securities Rulemaking Board, currently located at <http://emma.msrb.org>. *The foregoing internet address is included for reference only, and except as otherwise provided herein, the information on the internet site is not incorporated herein by this reference.*

Historical Financial Results

The following table shows a summary of the financial results of the Electric System for the five Fiscal Years ended June 30, 2021 through June 30, 2025. The table also sets forth the calculation of debt service coverage of outstanding Electric System obligations for these periods.

[Remainder of page intentionally left blank.]

TABLE 10
CITY OF ANAHEIM
ELECTRIC UTILITY FUND, FINANCIAL RESULTS OF THE ELECTRIC SYSTEM
(\$000)

	Fiscal Year Ended June 30,				
	2025	2024	2023	2022	2021
Revenues					
Sale of electricity:					
Residential	\$118,403	\$101,425	\$106,124	\$ 100,861	\$ 99,110
Commercial	151,961	128,567	122,100	124,625	116,632
Industrial	138,449	127,324	120,366	122,338	112,698
Other	5,144	4,676	3,094	3,216	3,568
Other Utilities (wholesale)	<u>10,427</u>	<u>14,105</u>	<u>35,320</u>	<u>20,640</u>	<u>27,286</u>
Total revenue from sale of electricity	<u>\$424,384</u>	<u>\$376,097</u>	<u>\$387,004</u>	<u>\$371,680</u>	<u>\$359,294</u>
RSA revenue recognized ⁽¹⁾	10,500	34,000	58,637	40,000	35,000
Other (including general interest income) ⁽²⁾	<u>46,778</u>	<u>46,834</u>	<u>43,081</u>	<u>33,503</u>	<u>40,937</u>
Total gross revenues	<u>\$481,662</u>	<u>\$456,931</u>	<u>\$488,722</u>	<u>\$445,183</u>	<u>\$435,231</u>
Expenses (excluding depreciation and amortization)					
Cost of purchased power ⁽³⁾	\$256,719	\$242,074	\$300,004	\$271,293	\$250,867
Fuel and generation ⁽⁴⁾	-	-	265	399	68
Operations & Maintenance	75,953	74,723	56,883	46,052	57,909
Right of way fee	<u>5,870</u>	<u>6,108</u>	<u>6,227</u>	<u>5,042</u>	<u>5,530</u>
Total expenses	<u>\$338,542</u>	<u>\$322,905</u>	<u>\$363,411</u>	<u>\$322,786</u>	<u>\$314,374</u>
Net revenues	143,120	\$134,026	\$125,311	\$122,398	\$120,857
Deposits to Renewal and Replacement Account	310	(713)	(246)	478	1,954
Surplus Revenues (a)	<u>142,810</u>	<u>134,739</u>	<u>125,557</u>	<u>121,920</u>	<u>118,903</u>
Qualified Obligations purchase payments (b) ⁽⁵⁾	70,725	67,013	64,414	60,840	58,765
Second Lien Qualified Obligations (c)	-	-	-	-	-
Net revenues after debt service payments	<u>72,085</u>	<u>67,726</u>	<u>61,143</u>	<u>61,080</u>	<u>60,138</u>
Transfers (to) Anaheim General Fund	(17,198)	(21,221)	(16,994)	(15,239)	(16,667)
Transfers (to) from other Anaheim funds	<u>1,949</u>	<u>507</u>	<u>253</u>	<u>1,422</u>	<u>179</u>
Balance for other purposes	<u>\$ 56,836</u>	<u>\$ 47,012</u>	<u>\$ 44,402</u>	<u>\$ 47,264</u>	<u>\$ 43,650</u>
Qualified Obligation (incl. Second Lien) debt service coverage (a/(b+c))	2.0x	2.0x	1.9x	2.0x	2.0x

⁽¹⁾ RSA is billed to customers through standard rates, and amounts collected are deferred and recorded as regulatory credits in the statement of net position. RSA revenue recognized, as shown, represents those amounts recognized as revenue and no longer recorded as regulatory credits. This revenue is typically recognized prior to fiscal year-end.

⁽²⁾ The other revenues include transmission revenues, natural gas sales and interest income. Other revenue was restated to exclude capital grants from operation revenue based on GASB 34.

⁽³⁾ Includes take-or-pay obligations with joint powers agencies. Cost of Purchased Power includes transmission costs and natural gas costs. Cost of Purchased Power reflects use of carbon allowance credits from the CARB to reduce renewable energy expenses.

⁽⁴⁾ Fuel and generation includes all expenses associated with the operation of the Kraemer CT Plant and the SJGS Unit 4, which are no longer in operation.

⁽⁵⁾ Refer to Table 8 herein for Qualified Obligations outstanding at June 30, 2025.

Source: Anaheim.

Management’s Discussion of Fiscal Year 2024-25 Operating Results

Total net position for the Fiscal Year ended June 30, 2025 was \$650.5 million, an increase of \$65.1 million or 11.1% from the prior fiscal year. Revenue for the Fiscal Year ended June 30, 2025 was \$492.7 million, an increase in total revenue of \$14.6 million or 3.1% from the prior fiscal year due to several factors. Total retail sales increased by \$51.5 million or 14.4% for the Fiscal Year ended June 30, 2025 compared to the prior fiscal year as a result of rate restructuring effective May 1, 2024, implemented in order to more effectively align the recovery of the Electric System’s costs with the nature of the costs incurred. Total wholesale sales decreased by \$3.7 million due to reduced available generation, which limited the amount of excess power the Electric System could sell into the wholesale market. Investment income had a net increase of \$1.6 million, mostly due to a favorable investment environment. The Electric System recognized a gain of \$5.3 million related to the reduction of a previously recorded obligation for the decommissioning of the Kraemer Combustion Turbine (CT) plant. In addition, capital contributions had a net decrease of \$15.4 million. Rate stabilization revenue recognized decreased by \$23.5 million, as a result of rate restructuring, allowing for a more stable and reliable revenue stream. The restructuring was designed to be revenue neutral for each customer.

Expenses for the Fiscal Year ended June 30, 2025, were approximately \$406.5 million, an increase of \$16.7 million or 4.3% from the prior fiscal year. The increase was primarily driven by higher purchased-power costs from the Intermountain Power Plant and an increase in renewable-resource purchases. The Electric System continues to manage its resource mix and procurement strategies to maintain cost stability while meeting Renewable Portfolio Standard (RPS) requirements. Operation, maintenance, and administration costs totaled \$76.0 million, an increase of \$1.2 million or 1.6% from the prior fiscal year. The increase is primarily due to salaries and related burdens from an increase in employee compensation under the current Memorandum of Understanding, which also led to higher payroll-related costs.

Labor Relations

As of June 30, 2025, APU has a total of 353 full-time and 52 part-time authorized positions. Of this total: the International Brotherhood of Electrical Workers (“IBEW”) Local 47 represents, approximately, 214 full-time and 25 part-time employees; the American Federation of State, County, and Municipal Employees District Council 36 (“AFSCME”) represents approximately 115 full-time and 10 part-time employees; and the Anaheim Municipal Employees Association (“AMEA”) represents 6 full-time employees. The City of Anaheim and IBEW, Local 47 established a memorandum of understanding for the general unit effective January 1, 2023 through January 1, 2026, for the part-time customer service unit effective January 1, 2023 through December 31, 2025, and for the professional management and part-time management units effective January 20, 2023 through January 16, 2026. The memorandum of understanding with AMEA expired July 3, 2025. The City is currently in negotiations with AMEA, and the general terms and conditions of the expired agreement remain in effect until a successor agreement is reached. The City also approved a memorandum of understanding with AFSCME effective July 1, 2023 through June 30, 2027. The City has not experienced any strike, work stoppage or other labor action by APU’s employees in the last five years.

Retirement Programs

Pension Plans. The City’s permanent employees, including APU’s Electric System employees, are covered by the California Public Employees Retirement System (“CalPERS”) through agent multiple-employer defined benefit plans administered by CalPERS, which acts as a common investment and administrative agent for participating public employers within the State. CalPERS issues publicly available reports that include a full description of the pension plans regarding benefit provisions, assumptions and membership information that can be found on the CalPERS website at www.calpers.ca.gov. *The foregoing*

internet address is included for reference only, and the information on the internet site is not incorporated by reference herein.

The City's defined benefit pension plans, the Miscellaneous Plan, Police Safety Plan and Fire Safety Plan, provide retirement and disability benefits, annual cost-of-living adjustments, and death benefits to plan members (who must be public employees) and beneficiaries. No employees assigned to the Electric System participate in the Police Safety Plan or Fire Safety Plan. Benefit provisions and all other requirements of the plans are established by State statute and City ordinance. California legislation, the Public Employee's Pension Reform Act ("PEPRA") of 2013, implemented certain limits on the amount and types of compensation that may be included in calculating pension benefits and new formulas for the calculation of pension benefits, as well as certain contribution requirements for the sharing of pension benefit costs, for new employees hired on or after January 1, 2013 who meet the definition of a new member under PEPRA.

The cost of the Miscellaneous Plan is funded through bi-weekly contributions from employees and from employer contributions by the City. Miscellaneous Plan employees hired prior to January 1, 2013 are generally required to contribute 8.00% of their annual covered salary. Miscellaneous Plan members hired on or after January 1, 2013 and who have no prior membership in any California public employee retirement system are required to contribute 6.75% of their annual covered salary. The member contribution can be paid by the employee or by the City on the employee's behalf in accordance with applicable labor agreements. The majority of Miscellaneous Plan employees hired prior to January 1, 2013 contribute the full 8.00% employee contribution plus 4.00% of the employer contribution, for a total of 12.00%. For employees hired on and after January 1, 2013 that are required to contribute at an employee rate of 6.75% of annual covered salary, the entire 6.75% is paid by such employees. In accordance with applicable State law, the contribution rate for all public employers is determined annually by the actuary and is effective on the July 1 following notice of a change in rate. Funding contribution amounts are determined annually on an actuarial basis as of June 30 by CalPERS. The actuarially determined rate applied to annual payroll is the estimated amount necessary to finance the costs of benefits earned by employees during the year, with an additional amount to finance any unfunded accrued liability. The City is required to contribute the actuarially determined remaining amounts necessary to fund the benefits for its members, using the actuarial basis recommended by CalPERS actuaries and actuarial consultants and adopted by the CalPERS Board of Administration. CalPERS establishes and amends the employer contribution rates. Beginning with Fiscal Year 2017-18, CalPERS began collecting employer contributions toward the plan's unfunded liability as dollar amounts rather than percentage of active payroll. Miscellaneous Plan provisions and benefits in effect at June 30, 2025 are as follows: the City's required employer contribution rate for the normal cost component of required contributions for the Miscellaneous Plan was approximately 12.61% of annual covered payroll for employees hired prior to January 1, 2013, and 12.61% of annual covered payroll for employees hired after January 1, 2013; the City's contribution to the unfunded accrued liability was approximately \$44,046,000.

[Remainder of page intentionally left blank.]

The table below shows the recent history of the actuarial accrued liability, the market value of assets, the funded ratio and the annual covered payroll for the City’s Miscellaneous Plan.

Valuation Date	Accrued Liability	Market Value of Assets	Unfunded Liability	Funded Ratio	Annual Covered Payroll
06/30/20	\$1,543,927,000	\$1,084,188,000	\$459,739,000	70.2%	\$124,700,000
06/30/21	1,619,285,000	1,308,881,000	310,404,000	80.8	111,733,000
06/30/22	1,681,617,000	1,183,362,000	461,482,000	71.9	119,690,000
06/30/23	1,741,021,000	1,230,615,000	510,406,000	70.7	133,453,000
06/30/24	1,815,111,000	1,322,020,000	493,091,000	72.8	147,681,000

Beginning with the June 30, 2013 valuation, CalPERS no longer uses an actuarial value of assets and instead uses the market value of assets to determine contribution rates per CalPERS’ direct rate smoothing policy. Under its direct rate smoothing policy, CalPERS employs an amortization and smoothing policy that will pay for all gains and losses over a fixed 30-year period with the increases or decreases in the rate spread directly over a 5-year period.

The PERS Board adopted a new amortization policy effective with the June 30, 2019 actuarial valuation. Under the new policy, amortization payments are determined as a level dollar amount. Investment gains or losses are amortized over a fixed 20-year period with a 5-year ramp up at the beginning of the amortization period. Non-investment gains or losses are amortized over a fixed 20-year period with no ramps. All changes in liability due to plan amendments (other than golden handshakes) are amortized over a 20-year period with no ramps. Changes in actuarial assumptions or changes in actuarial methodology are amortized over a 20-year period with no ramps. Changes in unfunded accrued liability due to a golden handshake are amortized over a period of five years. These changes will apply only to new unfunded accrued liability bases established on or after June 30, 2019.

The City’s required contributions to CalPERS fluctuate each year and include a normal cost component and a component equal to an amortized amount of the unfunded liability. Many assumptions are used to estimate the ultimate liability of pensions and the contributions that will be required to meet those obligations. The CalPERS Board of Administration has adjusted and may in the future further adjust certain assumptions used in the CalPERS actuarial valuations, which adjustments may increase the City’s required contributions to CalPERS in future years. One of the most significant factors used in determining the liability and the funding requirements is the rate of return that investments will yield prior to making payments, known as the discount rate. CalPERS approved an incremental reduction in the discount rate to be used in its actuarial valuation from 7.5% to 7.0% over the three Fiscal Years 2018-19 to 2020-21. The discount rate was automatically lowered in July 2021, from 7.0% to 6.8%, due to the CalPERS investment return for Fiscal Year 2020-21. Lower discount rates result in a comparative increase in the unfunded liability and the contributions required to meet those obligations. The City cannot provide any assurances that the City’s required contributions to CalPERS in future years will not significantly increase (or otherwise vary) from any past or current projected levels of contributions.

The table below sets forth certain information regarding the electric utility’s portion of the City’s required contributions to its CalPERS Miscellaneous Plan for the Fiscal Years ended June 30, 2021 through June 30, 2025, which amounts were paid in full by the Electric System in each of such fiscal years.

City of Anaheim
Schedule of Electric Utility Pension Plan Contributions

Fiscal Year	Contribution Funded by Electric Utility	Actuarially Determined Contribution Amount by Electric Utility	Electric Utility Contribution Deficiency (Excess) to Actuarially Determined Contribution	Electric Utility Contribution as a % of Covered Payroll
2020-21	\$11,089,000	\$11,089,000	--	41.49%
2021-22	11,318,000	11,318,000	--	39.06
2022-23	11,925,000	11,925,000	--	43.28
2023-24	12,366,000	12,366,000	--	39.59
2024-25	13,791,000	13,791,000	--	40.44

Source: Anaheim.

Effective for the Fiscal Year ended June 30, 2015, the City adopted Governmental Accounting Standards Board (“GASB”) Statement No. 68, affecting the reporting of pension liabilities for accounting purposes. Under GASB Statement No. 68, the City is required to report the Net Pension Liability (i.e., the difference between the Total Pension Liability and the Pension Plan’s Net Position or market value of assets) in its financial statements.

The table below summarizes certain information relating to the electric utility fund’s proportionate share of the Net Pension Liability of the City’s Miscellaneous Plan for the measurement periods ended June 30, 2020 through June 30, 2024 (as reported in the City’s electric utility fund audited financial statements as of the succeeding fiscal year). The electric utility’s proportion of the Net Pension Liability was based on a projection of its long-term share of contributions to the pension plan relative to the projected contributions of all participating funds of the City.

City of Anaheim Electric Utility Fund
Proportionate Share of the Net Pension Liability – Miscellaneous Plan

Measurement Period ⁽¹⁾	Proportionate Share of the Net Pension Liability ⁽²⁾	Electric Utility Share of the Net Pension Liability ⁽²⁾	Net Position as a % of Share of Total Pension Liability	Share of Net Pension Liability as a % of Its Covered Payroll
2019-20	22.2428%	\$98,035,000	71.16%	344.91%
2020-21	22.6166	58,177,000	83.58	200.76
2021-22	21.9206	101,160,000	71.94	401.77
2022-23	21.4389	102,420,000	72.04	388.28
2023-24	21.5888	96,530,000	74.74	325.92

⁽¹⁾ Measured using prior fiscal year annual actuarial valuation rolled forward to measurement date.

⁽²⁾ Reflects the electric utility’s share of the City’s Miscellaneous Plan Net Pension Liability of \$440,748,000, \$257,230,000, \$461,482,000, \$477,737,000 and \$447,132,000 for the five Fiscal Year measurement periods of 2019-20, 2020-21, 2021-22, 2022-23 and 2023-24, respectively.

Source: Anaheim.

Retiree Health Benefits. In addition to the defined benefit pension plan described above, the City also maintains a program providing “other post-employment benefits” (“OPEB”) to eligible retirees, including health care and disability coverage and death benefits. The City made significant changes to its OPEB program during Fiscal Year ended June 30, 2006. For City employees hired prior to January 1, 1996

(other than those represented by the Anaheim Police Association, the Anaheim Fire Association or the IBEW), the length of service credit was frozen for all employees eligible for the benefit. Length of service, a factor in determining the amount of the benefit earned, will not accrue beyond December 31, 2005. Employees hired on or after January 1, 1996 (other than those represented by the Anaheim Police Association or the Anaheim Fire Association) are no longer eligible for City funding of all or a portion of post-employment medical benefits. For City employees represented by the IBEW who had not retired as of October 15, 2005, medical benefits only for future retirees are to be provided through a trust established by the IBEW. Benefits are determined by the trustees of the trust and the City's liability is limited to specified percentages of employee pay.

City employees hired on or after January 1, 1996 and before January 1, 2002 (other than those represented by the Anaheim Police Association, the Anaheim Fire Association or the IBEW) were transitioned from the former defined benefit OPEB medical plan to a defined contribution OPEB medical plan. The City made a one-time contribution of \$1,685,000 to a newly established retiree health savings account for those eligible employees. Participation in the retiree health savings account is mandatory for this transitional group of employees.

Based on eligibility status, retirees may participate in any health plan made available to active City employees. The City has several plans with different contribution levels and benefit provisions. The City's contributions vary up to 100% of annual premium cost, depending on the employee's Medicare eligibility, year of hire, age and employee group. At June 30, 2025, 1,337 retirees or surviving spouses met the various eligibility requirements and were receiving medical benefits.

The City's contributions toward the cost of its OPEB program are generally advance funded on an actuarial basis to a dedicated reserve, but annual contributions are not required. To pre-fund OPEB liabilities, the City participates in the California Employers' Retiree Benefit Trust, an agent multiple employer plan consisting of an aggregation of single-employer plans, with pooled administrative and investment functions that are administered by CalPERS. As of the actuarial valuation date of June 30, 2023, the unfunded liability for the City's Post-Employment Medical Benefits Program was \$101,950 or 50% funded.

For Fiscal Years prior to Fiscal Year 2017-18, the City's reported annual OPEB cost (expense) was determined in accordance with the parameters of GASB Statement No. 45. The electric utility paid its allocated share of the City's annual full cost for current premiums.

Effective for Fiscal Year 2017-18, the City follows the provisions of GASB Statement No. 75, Accounting and Financial Reporting for Postemployment Benefits Other Than Pensions ("GASB No. 75") affecting the reporting of OPEB liabilities for accounting purposes. GASB No. 75 replaces the requirements of GASB Statement No. 45. GASB No. 75 establishes standards for employers with other postemployment liabilities for recognizing and measuring net OPEB liabilities, along with deferred inflows and outflows of resources, and expenses/expenditures related to the other postemployment liability. GASB No. 75 does not establish requirements for funding.

City contributions to the OPEB Plan occur as benefits are paid to retirees or contributions to the OPEB Trust. The City contributes an amount not less than the annual actuarially determined contribution measured in accordance with the parameters of GASB No. 75. The table below sets forth certain information regarding the electric utility's allocated share of the City's annual contributions to the OPEB Plan for the Fiscal Years ended June 30, 2021 through June 30, 2025, including the relation of such contributions to the actuarially determined contribution amount for such fiscal year.

City of Anaheim
Schedule of Electric Utility OPEB Plan Contributions

Fiscal Year	Contribution Funded by Electric Utility	Actuarially Determined Contribution Amount by Electric Utility	Electric Utility Contribution Deficiency (Excess) to Actuarially Determined Contribution	Electric Utility Contribution as a % of Covered Payroll
2020-21	\$2,049,000	\$1,773,000	(276,000)	8.04%
2021-22	1,970,000	1,781,000	(189,000)	7.61
2022-23	1,774,000	1,774,000	--	6.48
2023-24	1,863,000	1,863,000	--	6.09
2024-25	1,663,000	1,663,000	--	5.44

Source: Anaheim.

The table below summarizes certain information relating to the electric utility fund's proportionate share of the City Net OPEB Liability for the measurement periods ended June 30, 2020 through June 30, 2024 (as reported in Anaheim's electric utility fund audited financial statements as of the succeeding fiscal year).

City of Anaheim Electric Utility Fund
Proportionate Share of the Net OPEB Liability

Measurement Period ⁽¹⁾	Proportionate Share of the Net OPEB Liability ⁽²⁾	Electric Utility Share of the Net OPEB Liability ⁽²⁾	Net Position as a % of Share of Total OPEB Liability	Share of Net OPEB Liability as a % of Its Covered Payroll
2019-20	13.0617%	\$20,912,000	37.91%	76.36%
2020-21	12.5016	13,395,000	53.77	52.59
2021-22	12.2649	15,052,000	46.79	58.12
2022-23	12.0136	13,800,000	50.04	50.41
2023-24	12.2419	12,481,000	55.59	40.80

⁽¹⁾ Measured using actuarial valuation as of the measurement date.

⁽²⁾ Reflects the electric utility's share of the City's Net OPEB Liability of \$160,100,000, \$107,149,000, \$122,722,000, \$114,869,000 and \$101,950,000 for the fiscal year measurement periods of 2019-20, 2020-21, 2021-22, 2022-23 and 2023-24, respectively.

Source: Anaheim.

Additional information regarding the City's retirement plans and OPEB, including information regarding the assumptions used to determine the pension and OPEB liabilities and the funding requirements therefor, can be found in Notes 10 and 11 and the Required Supplementary Information to the City's audited financial statements included in the City's annual comprehensive financial report, which may be obtained on the Electronic Municipal Market Access website of the Municipal Securities Rulemaking Board, currently located at <http://emma.msrb.org>.

Litigation Affecting the Electric System

General. At any given time, the City has pending against it a number of claims and lawsuits arising out of matters usually incidental to the operation of a utility such as the Electric System. The City is of the view that, if determined adversely to the City, the actual damage awards likely to be ultimately paid with respect to any such current claims and lawsuits would not, in the aggregate, materially impair the City's ability to pay its Electric System obligations.

In addition, there are various ongoing proceedings to which the City is not a party that involve projects in which the City has an interest and which comprise a portion of the current resource portfolio of the Electric System; although the City is not a party to these such proceedings, their outcome may impact the costs and operations of the affected project.

Federal Prosecution. On August 16, 2023, former Anaheim mayor, Harry Sidhu, agreed to plead guilty to four felony charges consisting of obstruction of justice, wire fraud, and two counts of making false statements to the Federal Bureau of Investigation (“FBI”) and Federal Aviation Administration (“FAA”). In his plea agreement with federal prosecutors, Mr. Sidhu admitted that he sought to become a member of the City’s negotiating team and provided confidential information related to the sale of Angel Stadium of Anaheim to people working for the Angels. On March 28, 2025, a United States District Court sentenced Mr. Sidhu to two months in prison, a year of supervised released, and a \$55,000 fine for his crimes.

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.

[Remainder of page intentionally left blank.]

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 POU’s 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

<u>Resource Type</u>	<u>Capacity Percentage⁽¹⁾</u>	<u>Energy Percentage⁽²⁾</u>
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	<u><u>100.0%</u></u>	<u><u>100.0%</u></u>

⁽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.

[Remainder of page intentionally left blank.]

**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 Lyndyl, 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 MWh 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 SCPA 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 SCPA, 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 POU's, 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 POU's 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 SCPA (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, \pm 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, SCPA, 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 SCPA's member-related interests of the Mead-Adelanto Transmission Project (SCPA'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 SCPA that obligate the Department until 2030 to pay for its share of SCPA'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 SCPA'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 SCPA for SCPA'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)

Operating Statistics	Fiscal Year Ended June 30				
	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	<u>\$5,308,300</u>	<u>\$4,825,368</u>	<u>\$4,958,539</u>	<u>\$4,593,760</u>	<u>\$4,268,478</u>
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	<u>\$5,308,300</u>	<u>\$4,825,368</u>	<u>\$4,958,539</u>	<u>\$4,593,760</u>	<u>\$4,268,478</u>
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	<u>1,837,863</u>	<u>1,693,747</u>	<u>1,570,429</u>	<u>1,430,993</u>	<u>1,323,158</u>
Adjusted Operating Expenses ⁽³⁾⁽⁵⁾	<u>\$3,386,829</u>	<u>\$3,248,142</u>	<u>\$3,454,645</u>	<u>\$3,068,311</u>	<u>\$2,853,249</u>
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⁾	<u>\$2,333,758</u>	<u>\$2,043,011</u>	<u>\$1,994,644</u>	<u>\$1,627,796</u>	<u>\$1,663,991</u>
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	<u>\$ 783,097</u>	<u>\$ 750,314</u>	<u>\$ 708,133</u>	<u>\$ 667,165</u>	<u>\$ 638,818</u>
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:

[Remainder of page intentionally left blank.]

**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	<u>\$4,180</u>		<u>\$3,435</u>

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 emissions 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 (“CO₂”) per MWh for “covered procurements” by POU, such as the Department. SB 1368 also prohibits POU 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 POU, 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 POU, 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 POU 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 CO₂ 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 CO₂ 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 CO₂ emissions reflecting the application of best systems emissions reduction (BSER), which EPA determined to be CCS with 90% capture of CO₂. 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 CO₂ 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 CO₂ 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 0.0000065 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 NO_x 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 through 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 (“EPAAct 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. EPAAct 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 (“EPAAct 2005”) addresses a wide array of matters that affect the entire electric utility industry, including the Department.

Subject to certain conditions and limitations, EAct 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.

EAct 2005 provides for criminal penalties for manipulative energy trading practices.

EAct 2005 repealed the Public Utility Holding Company Act of 1935, which prohibited certain mergers and consolidations involving electric utilities. EAct 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 EAct 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.

EAct 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 EAct 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.

EAct 2005 authorizes FERC to compel the siting of certain transmission lines if FERC determines that a state has unreasonably withheld approval.

EAct 2005 promotes increased imports of liquefied natural gas and includes incentives to support the development of renewable energy technologies. EAct 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. The 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.

CITY OF RIVERSIDE

The following is certain information concerning the City of Riverside (“Riverside” or the “City”) and its Public Utilities Department (the “Riverside Public Utilities Department”) and such Department’s electric utility (the “Riverside Electric System” or the “Electric System”), prepared by Riverside for inclusion herein. This information does not purport to cover all aspects of the Riverside Electric System’s business, operations and financial position. The June 30, 2025 information provided herein is preliminary and unaudited.

History of the Electric System

Riverside was a pioneer in the transmission and distribution of electric power. The municipal electric system, which was constructed in 1895, was among the first of eight such municipally-owned systems in the State of California (the “State”) prior to the turn of the century. The Riverside Electric System had been fundamentally a sub-transmission and distribution system, although Riverside did generate part of its own power from 1900 to 1924. Power was purchased exclusively from Southern California Edison Company (“SCE”) from 1950 to May 1976. At that time, Riverside began receiving non-firm energy purchased from the Nevada Power Company, which was delivered to Riverside by SCE. Since that time, Riverside has developed a number of other power supply resources, including the acquisition and construction of local generation assets, participation in joint powers agency projects and long and short-term power purchases with a variety of providers, as reflected above.

Management

Under the provisions of the State Constitution and Article XII of the City Charter, Riverside owns and operates both electrical and water public utility services for its residents. The Riverside Public Utilities Department exercises jurisdiction over the electric and water utilities owned, controlled and operated by Riverside. The Riverside Public Utilities Department is under the management and control of the City Manager, subject to the powers and duties vested in the Riverside Board of Public Utilities (the “Riverside Board” or the “Board”) and the City Council, and is supervised by the Public Utilities General Manager who is responsible for design, construction, maintenance and operation of the electric and water utilities.

Management of the Riverside Public Utilities Department is as follows:

Mr. David A. Garcia, General Manager, holds a Bachelor of Science in Environmental Sciences from the University of California, Riverside and a master’s degree in Environmental Policy and Planning from California State University, Fullerton. He is also certified as a Grade 5 Water Treatment and Distribution Operator by the California State Water Resources Control Board. Mr. Garcia has over 30 years of water utility experience throughout the Santa Ana River Watershed. He last served as the Director of Water Operations for Eastern Municipal Water District and, previously, in various management roles, including Water Operations Manager for the Riverside Public Utilities Department.

Mr. Brian Seinturier, Assistant General Manager, Finance and Administration holds a bachelor’s degree in Business Administration, with an emphasis in Accounting, from the University of California, Riverside and is a Certified Public Accountant. He has over 27 years of experience in public sector accounting and finance. He has worked for Riverside Public Utilities since July 2007.

Dr. Scott M. Lesch, Assistant General Manager, Power Resources, holds a master’s degree in Statistics from Carnegie Mellon University and a Ph.D. in Applied Statistics from the University of California, Riverside. He has worked for Riverside Public Utilities since 2009. Prior to joining Riverside Public Utilities, he worked for 21 years at the University of California Riverside campus as an Environmental Statistician (in the Department of Environmental Science) and as a Principal Consulting Statistician (in the Department of Statistics).

Ms. Tracy Sato, Assistant General Manager, Strategic Initiatives, holds a Bachelor of Science in Urban and Regional Planning from California Polytechnic State University, Pomona and a master's degree in Urban and Regional Planning with a specialization in Environmental Planning from Virginia Polytechnic Institute and State University. She has over 15 years of professional and technical experience as an urban planner, including several years that included GIS programming and data management, and about 13 years in the electric utility industry. She has been with the Riverside Public Utilities Department since 2017.

Mr. Daniel Honeyfield, Assistant General Manager, Energy Delivery, holds a Bachelor of Science in Electrical and Computer Engineering from California Polytechnic State University, Pomona, a Master of Business Administration, with emphasis in Technology Management, from the University of Phoenix, and a professional engineering license through the State. He has over 18 years of utility experience, serving seven years as Engineering Manager for the Sacramento Municipal Utility District and in various roles for Riverside Public Utilities, including Senior Electric Utilities Engineer.

Ms. Robin Glenney, Assistant General Manager, Water Delivery, holds a Bachelor of Science in Biology from California State University, Long Beach and a master's degree in Environmental Engineering from California State University, Fullerton. She has over 17 years of experience in environmental and regulatory compliance and a decade of expertise in utility management. Prior to her current role, she served as the Water Operations Manager with Riverside Public Utilities.

Board of Public Utilities

The Board, created by Article XII, Section 1201, of the City Charter, consists of nine members appointed by the City Council. As set forth in Article XII, the Board, among other things, has the power and obligation to: (1) consider the biennial budget for the Riverside Public Utilities Department during the process of its preparation and make recommendations with respect thereto to the City Council and the City Manager; (2) within the limits of the budget of the Riverside Public Utilities Department, authorize and award bids for the purchase of equipment, materials or supplies exceeding the sum of \$50,000, and authorize the acquisition, construction, improvement, extension, enlargement, diminution or curtailment of all or any part of any public utility system, and no such purchase, acquisition, construction, improvement, extension, enlargement, diminution or curtailment may be made without such authorization; (3) within the limits of the budget of the Riverside Public Utilities Department, make appropriations from the contingency reserve fund for capital expenditures directly related to the appropriate utility function; (4) require of the City Manager monthly reports of receipts and expenditures of the Riverside Public Utilities Department, segregated as to each separate utility, and monthly statements of the general condition of the Riverside Public Utilities Department and its facilities; (5) establish rates for water and electric revenue producing utilities owned, controlled, or operated by the City, but subject to the approval of the City Council; (6) approve or disapprove the appointment of the Utilities General Manager, who shall be the Riverside Public Utilities Department head; (7) make such reports and recommendations to the City Council regarding the Riverside Public Utilities Department as it deems advisable; (8) designate its own secretary; and (9) exercise such other powers and perform such other duties as may be prescribed by ordinance not inconsistent with any of the provisions of the City Charter.

Employee Relations

As of July 1, 2025, 473 City employees were assigned specifically to the Riverside Electric System. Substantially all of the non-administrative City personnel assigned to the Riverside Electric System are represented by the International Brotherhood of Electrical Workers ("IBEW"). Riverside and IBEW are parties to a Memorandum of Understanding that expires on December 31, 2027. Portions of the administrative staff are represented by the Service Employees International Union ("SEIU"). Riverside and the SEIU are parties to a Memorandum of Understanding that expires on June 30, 2028. While not under a memorandum of understanding, all unrepresented employees have compensation and benefit

packages approved by the City Council. On September 2, 2025, the City Council approved changes for unrepresented employees through June 2028.

The Riverside Electric System has faced no strikes or other work stoppages within the last ten years, and the City does not anticipate any in the near future.

Retirement Programs

Employee Retirement System

Retirement benefits to City employees, including those assigned to the Riverside Electric System, are provided through the City's participation in the California Public Employees Retirement System ("CalPERS"), an agency, multiple-employer, public employee retirement system that acts as a common investment and administrative agency for participating public entities within the State. CalPERS issues a separate, publicly available financial report that includes financial statements and required supplemental information of participating public entities within the State. Copies of the CalPERS annual financial report may be obtained from the CalPERS Executive Office, Lincoln Plaza Complex, 400 Q Street, Sacramento, California 95811 or at www.calpers.ca.gov.

Riverside has a multiple-tier retirement plan with benefits varying by plan. All permanent full-time and selected part-time employees are eligible for participation in CalPERS. Benefits vest after five years of service and are determined by a formula that considers the employee's age, years of service and salary. All of the bargaining units included in the Miscellaneous CalPERS Plan, including Management, SEIU, and IBEW employees of the Electric System and the City's water utility ("Water System"), agreed to change the calculation of the CalPERS retirement benefit for new employees from an amount derived from the highest year of salary to an amount derived from the average of the highest three years of salary, which addressed concerns associated with salary increases in the year immediately prior to retirement. This change was effective for employees hired on or after December 9, 2011.

The California Public Employees' Pension Reform Act of 2012 ("PEPRA") enacted statewide pension reforms effective January 1, 2013, which the City has implemented. Employees hired after January 1, 2013, may retire at age 62 and receive 2.0% of their highest salary for each year of service completed. The formula is adjusted to encourage employees to retire at later ages, with a 2.5% cap at age 67. The average highest three years of salary continue to be used to calculate the retirement benefit under the new plan. CalPERS also provides death and disability benefits. These benefit provisions and all other requirements are established by State statute and City ordinance.

Under the current plan, Riverside pays the employees' contribution to CalPERS for employees hired on or before specific dates as follows:

- 1st Tier -
 - The retirement formula is 2.7% at age 55 for unrepresented employees hired before October 19, 2011. Effective January 1, 2021, the employees contribute the entire required amount of 8% of their pensionable income.
 - The retirement formula is 2.7% at age 55 for SEIU employees hired before June 7, 2011. Effective November 1, 2020, employees contribute the entire required amount of 8% of their pensionable income.
 - The retirement formula is 2.7% at age 55 for IBEW employees hired before October 19, 2011. Effective January 1, 2020, employees contribute the entire required amount of 8% of their pensionable income.
- 2nd Tier - The retirement formula is 2.7% at age 55, and:

- SEIU employees hired on or after June 7, 2011 pay their share (8%) of contributions.
- All other Miscellaneous Plan employees hired on or after October 19, 2011 pay their share (8%) of contributions.
- 3rd Tier - The retirement formula is 2% at age 62 for new members hired on or after January 1, 2013 and the employee must pay the employee share ranging from 7% to 8% based on bargaining group classification. Classic members (employees who were CalPERS members prior to December 31, 2012) hired on or after January 1, 2013 may be placed in a different tier.

PEPRA also established a cap on the amount of compensation that can be used to calculate the retirement benefit for employees hired on or after January 1, 2013, which limits the benefit to 120% of the Social Security wage index limit for 2018 of \$145,666 for employees not covered by Social Security and \$121,388 for employees participating in Social Security. This cap will be adjusted annually by the Consumer Price Index for all Urban Consumers. PEPRA also prevents employers from offering defined benefit plans for compensation in excess of the cap, but does allow for contributions to a defined contribution plan for compensation in excess of the cap. PEPRA specifies that employees will not have a vested right to any employer contributions to defined contribution plans related to this provision. The City of Riverside has not made any enhancements to the compensation package for employees hired on or after January 1, 2013, with compensation exceeding the cap.

CalPERS Discount Rate Adjustment. On March 14, 2012, the CalPERS Board voted to lower the CalPERS' rate of expected price inflation and its investment rate of return (net of administrative expenses) (the "CalPERS Discount Rate") from 7.75% to 7.5%. On November 17, 2015, the CalPERS Board approved a new funding risk mitigation policy to incrementally lower the CalPERS Discount Rate by establishing a mechanism whereby such rate is reduced by a minimum of 0.05% to a maximum of 0.25% in years when investment returns outperform the existing CalPERS Discount Rate by at least four percentage points. On December 21, 2016, the CalPERS Board voted to lower the CalPERS Discount Rate to 7.0% over the three years from Fiscal Years 2018-19 to 2020-21. The discount rate was automatically lowered again in July 2021 from 7.0% to 6.9% due to the CalPERS investment return for Fiscal Year 2020-21. This remains the current discount rate as of June 30, 2025. Lowering the CalPERS Discount Rate likely means employers that contract with CalPERS to administer their pension plans (such as the City) will see increases in their normal costs and unfunded actuarial liabilities. Active members hired after January 1, 2013, under PEPRA, will likely also see their contribution rates rise.

The Electric System's total contribution to CalPERS as of June 30, 2025 and 2024 was \$7,765,000 and \$6,060,000, respectively. In addition, the Electric System is obligated to pay its share of the City's pension obligation bonds, which the City issued in 2005 and refinanced a portion in May 2017 (the "Pension Obligation Bonds"). The City issued additional Pension Obligation Bonds in June 2020. The Electric System's total proportionate share of the outstanding principal amount of the Pension Obligation Bonds was \$52,616,000 and \$58,291,000 as of June 30, 2025 and 2024, respectively, which is payable as an Operating and Maintenance Expense. That share will amortize based on the amortization schedule of the Pension Obligation Bonds. Citywide information concerning elements of the net pension liability, contributions to CalPERS and recent trend information may be found in the notes to the basic financial statements in the City's Annual Comprehensive Financial Report ("ACFR") for the Fiscal Year ended June 30, 2025, which may be obtained on the City's website after February 2026.

More recent information as to the actuarial status of the City's Miscellaneous Plan has been provided in CalPERS' Actuarial Valuation for the Miscellaneous Plan of the City of Riverside as of June 30, 2024, with respect to the City.

As shown in the table below, the report provides a recent history of the City's contribution rates for its Miscellaneous Plan, as determined by the annual actuarial valuation. The following table does not account for prepayments or benefit changes made in the middle of the year.

Table 1
City of Riverside
CalPERS Miscellaneous Plan
History of City's Contribution Rate
and Unfunded Liability Payments Due⁽¹⁾

Fiscal Year	Employer Normal Cost	Unfunded Rate	Total Employer Contribution Rate	Unfunded Liability Payment Due
2011-12	11.823%	6.615%	18.438%	N/A
2012-13	11.814	6.463	18.277	N/A
2013-14	11.851	6.463	18.314	N/A
2014-15	11.554	7.440	18.994	N/A
2015-16 ⁽²⁾	11.871	9.141	21.012	N/A
2016-17 ⁽²⁾	12.250	10.728	22.978	N/A
2017-18 ⁽²⁾	12.136	N/A	N/A	\$15,683,043
2018-19 ⁽²⁾	12.314	N/A	N/A	\$19,422,351
2019-20 ⁽²⁾	12.866	N/A	N/A	\$22,752,102
2020-21 ⁽³⁾	13.071	N/A	N/A	\$24,338,697
2021-22 ⁽⁴⁾	12.730	N/A	N/A	\$11,197,247
2022-23 ⁽⁵⁾	12.460	N/A	N/A	\$11,860,450
2023-24 ⁽⁶⁾	13.560	N/A	N/A	\$0
2024-25 ⁽⁷⁾	13.300	N/A	N/A	\$4,928,524
2025-26 ⁽⁸⁾	12.930	N/A	N/A	\$14,555,060
2026-27 ⁽⁹⁾	12.290	N/A	N/A	\$20,243,138

⁽¹⁾ Beginning with Fiscal Year 2017-18, CalPERS will collect employer contributions toward the plan's unfunded liability as dollar amounts instead of the prior method of a contribution rate. This change will address potential funding issues that could arise from a declining payroll or reduction in the number of active members in the plan. Funding the unfunded liability as a percentage of payroll could lead to the underfunding of the plans. Although employers will be invoiced at the beginning of the Fiscal Year for their unfunded liability payment, the plan's normal cost contribution will continue to be collected as a percentage of payroll.

⁽²⁾ Sourced from CalPERS' Annual Valuation Report, dated July 2018. The rates reflect the effect of PEPRA enactment. PEPRA is discussed earlier in this section.

⁽³⁾ Sourced from CalPERS' Annual Valuation Report, dated July 2019.

⁽⁴⁾ Sourced from CalPERS' Annual Valuation Report, dated July 2020.

⁽⁵⁾ Sourced from CalPERS' Annual Valuation Report, dated July 2021.

⁽⁶⁾ Sourced from CalPERS' Annual Valuation Report, dated July 2022.

⁽⁷⁾ Sourced from CalPERS' Annual Valuation Report, dated July 2023.

⁽⁸⁾ Sourced from CalPERS' Actuarial Valuation for the Miscellaneous Plan of the City of Riverside as of June 30, 2023.

⁽⁹⁾ Sourced from CalPERS' Actuarial Valuation for the Miscellaneous Plan of the City of Riverside as of June 30, 2024.

In addition, the report provides the recent history of the Actuarial Accrued Liability, the Market Value of Assets, the funded ratio and the annual covered payroll as shown in the table below. The funded ratio is an indicator of the short-term solvency of the plan.

[This space intentionally left blank.]

Table 2
City of Riverside
CalPERS Miscellaneous Plan
City's Funding History

Valuation Date (June 30)	Actuarial Accrued Liability	Market Value of Assets (MVA)	Funded Ratio	Annual Covered Payroll
2011	\$ 998,216,259	\$ 786,080,314	78.7%	\$ 108,106,192
2012	1,046,199,578	766,804,452	73.3	110,037,157
2013	1,086,925,211	847,232,156	77.9	110,552,014
2014	1,180,549,024	972,056,589	82.3	110,534,205
2015	1,228,644,007	969,285,454	78.9	111,185,202
2016	1,277,998,975	949,866,377	74.3	113,072,729
2017	1,317,421,178	1,029,759,135	78.2	118,644,799
2018	1,401,014,728	1,090,728,598	77.9	119,987,924
2019	1,462,992,745	1,138,310,022	77.8	126,381,375
2020	1,520,527,010	1,368,575,052	90.0	129,401,884
2021	1,570,873,013	1,638,143,404	104.3	128,059,046
2022	1,639,823,585	1,473,674,465	89.9	129,289,938
2023	1,752,961,359	1,517,524,223	86.6	145,914,865
2024	1,839,720,766	1,599,516,796	86.9	157,710,038

Other Post-Employment Benefits

The Electric System contributes to two single-employer defined benefit healthcare plans: the Stipend Plan and the Implied Subsidy Plan. These plans provide other post-employment health care benefits (“OPEB”) for eligible retirees and beneficiaries.

The Stipend Plan is available to eligible IBEW retirees and beneficiaries pursuant to their collective bargaining agreement. Benefit provisions for the Stipend Plan are established and amended through the memorandum of understanding with IBEW as approved by the City Council, which currently provides for the Electric System to make contributions on a “pay-as-you-go-basis.” The union establishes the benefits paid to retirees and the City is not required by law or contractual agreement to provide funding for the plan other than as specified in the memorandum of understanding, which currently provides for a contribution of \$100 per month per active IBEW employee.

The Implied Subsidy Plan allows retirees and current employees to be insured together as a group and allows a lower rate for retirees than if they were insured separately. Upon retirement, retirees pay the full amount of applicable premiums; however, they participate in the Electric System’s healthcare plans and, as such, an implicit subsidy exists. The Riverside Electric System’s contributions to the Implied Subsidy Plan are established by the City Council. The Riverside Electric System is not required by law or contractual agreement to provide funding other than the pay-as-you-go amount necessary to provide current benefits to eligible retirees and beneficiaries.

Effective for the Fiscal Year ended June 30, 2018, the Governmental Accounting Standards Board (“GASB”) issued its Statement No. 75, Accounting and Financial Reporting for Postemployment Benefits Other Than Pensions (“OPEB”). This statement requires a net OPEB liability to be reported on the balance sheet of the financial statements, similar to the net pension liability. GASB Statement No. 75 requires that most changes in the net OPEB liability be included in OPEB expense in the period of the change. For the

Fiscal Year ended June 30, 2025, the OPEB expense recorded for the Riverside Electric System was \$526,000. The Riverside Electric System's net OPEB liability as of June 30, 2025 was \$10,807,000.

Additional information regarding Riverside's citywide retirement plans and OPEB, including information regarding the assumptions used to determine the pension and OPEB liabilities and the funding requirements therefor, can be found in Notes 6 and 7 to Riverside Public Utilities Department's audited Financial Statements for the Fiscal Year ended June 30, 2025, which may be obtained on the City's website after February 2026.

Electric System - General

The Riverside Electric System operates as a vertically integrated utility providing service to virtually all electric consumers within the city limits of Riverside, which encompasses 81.5 square miles. The Electric System provides service throughout the City to domestic, commercial, industrial, agricultural, municipal and other customers. In Fiscal Year 2024-25, the number of metered customers of the Electric System was 114,180.

Electric System Facilities

Power Supply

The Riverside Electric System's power supply requirements are met through:

- (i) the City's internal generation consisting of 40 MW, simple-cycle, combustion turbines ("Springs Generating Project") and the City's four-unit, 196 MW, power plant Riverside Energy Resource Center ("RERC") Units 1, 2, 3 and 4 and City's combined-cycle Clearwater Cogeneration Facility ("Clearwater") located in Corona, California (29.5 MW) (see the caption "—City-Owned Generating Facilities");
- (ii) entitlements in the Intermountain Power Project ("IPP") Generating Station, the Hoover Power Plant and through its participation in the Southern California Public Power Authority (the "Authority"), the Authority's Palo Verde Nuclear Generating Station Project ("PVNGS") (see the caption "—Entitlements");
- (iii) long-term power purchase agreements for renewable energy (see the caption "—Renewable Resources");
- (iv) purchases of firm energy from various western utilities when it is available at an economical price or when needed to satisfy periods of peak demand (see the caption "—Firm Contracts and Market Purchases"); and
- (v) energy purchases through the California Independent System Operator (the "CAISO") centralized markets (see the caption "—Firm Contracts and Market Purchases").

For Fiscal Year 2024-25, the overall average net cost of generation and transmission was 8.6 cents per kilowatt-hour ("kWh").

The following table sets forth the amounts in MWh and percentages of electricity obtained by Riverside during the Fiscal Year ended June 30, 2025.

Table 3
Riverside Electric System
Annual Electricity Supply ⁽¹⁾
Fiscal Year Ended June 30, 2025

<u>Resources</u>	<u>MWh</u>	<u>Percentage</u>
Renewable Resources	813,500	35.9%
Firm Contracts and Market Purchases	711,300	31.4
IPP Generating Station.....	546,800	24.1
Springs, RERC and Clearwater.....	69,100	3.0
PVNGS	102,300	4.5
Hoover Power Plant.....	24,900	1.1
Total	2,267,900	100%

⁽¹⁾ Includes native load (the supply for end-use customers that the Electric System is obligated to serve), losses and wholesale power sales. Reflects preliminary results based on available information to date; subject to change.

During Fiscal Year 2024-25, the Electric System generated and purchased a total of 2,267,900 megawatt hours (“MWhs”) of electricity for delivery to customers throughout the City. The system peak for the Fiscal Year ended June 30, 2025 was 658.5 megawatts (“MWs”) on September 6, 2024. The following table sets forth, in MWh of electricity, the total purchases of power and Riverside Electric System peak demand during the periods shown.

Table 4
Riverside Electric System
Total Energy Generated and Purchased and Peak Demand

	Fiscal Year Ended June 30,				
	<u>2025*</u>	<u>2024</u>	<u>2023</u>	<u>2022</u>	<u>2021</u>
From City’s Own Generation (MWh) ⁽¹⁾	69,100	68,300	92,600	68,000	95,400
From Other Sources (MWh).....	<u>2,198,800</u>	<u>2,130,000</u>	<u>2,147,300</u>	<u>2,214,900</u>	<u>2,166,900</u>
System Total (MWh) ⁽²⁾	<u>2,267,900</u>	<u>2,198,300</u>	<u>2,239,900</u>	<u>2,282,900</u>	<u>2,262,300</u>
System Peak Demand (MW).....	658.5	589.8	647.8	575.9	630.3
System Native Load (MWh)	2,157,000	2,065,000	2,161,000	2,144,000	2,122,000

* Reflects preliminary results based on available information to date; subject to change.

⁽¹⁾ Fluctuations in City generation reflect changes in energy market prices and peak electricity needs, which can vary based on weather and other circumstances.

⁽²⁾ Before system losses. Excludes wholesale sales.

City-Owned Generating Facilities

City-owned generating facilities include the City’s Springs Generating Project, RERC Units 1, 2, 3 and 4 and Clearwater.

Springs Generating Project. The Springs Generating Project (which began commercial operations in 2002) consists of four natural gas, simple-cycle turbine generators, each with a gross capacity of 10 MW (for a total of 40 MW). The Springs Generating Project is used primarily to serve the Electric System’s native load during periods of super peak power demand in the City. These facilities are also available to be used if normal operations of the Electric System are disrupted and will provide essential emergency services within the City, such as hospital care, traffic control and police and fire dispatching.

RERC Units 1, 2, 3 and 4. RERC Units 1 and 2 are natural gas-fired, simple-cycle plants located in the City, consisting of two General Electric LM 6000 SPRINT combustion turbines, nominally rated at 49 MW each (net power at site conditions) and related sub-transmission lines. The construction of the units was completed in June 2006. The units have a combined operating capacity of 98 MW with emission levels that allow for approximately 1,200 hours of run time per unit, per year. RERC Units 3 and 4 are of the same make, model and operating characteristics as RERC Units 1 and 2 and achieved commercial operation on April 1, 2011. RERC Units 3 and 4 have a combined operating capacity of 98 MW with emission levels that allow for approximately 150 hours of run time per unit, per month. All four RERC Units serve the Electric System’s native load when economically feasible or during periods of peak power demand in the City, enhance reliability and service delivery to customers and provide energy and ancillary services in the CAISO markets.

Clearwater. Clearwater consists of a single, General Electric LM 2500 combustion turbine generator operating in combined cycle with one RENTECH heat recovery steam generator and one SHIN NIPPON steam turbine generator. The gross plant output of Clearwater is 29.5 MW. The City acquired Clearwater from the City of Corona, California, effective September 1, 2010. Clearwater has been included in the City’s resource portfolio and the necessary air quality permits to operate Clearwater up to a baseload configuration are in place. Clearwater is also utilized by the City to meet the local resource adequacy requirements of the CAISO.

Decommissioning of SONGS. The City has a 1.79% undivided ownership interest in Units 2 and 3 of San Onofre Nuclear Generating Station (“SONGS”); however, on June 7, 2013, SCE, as principal owner and operating agent, announced its plan to retire Units 2 and 3 of SONGS permanently, triggering the start of decommissioning. Consequently, SONGS is no longer a power resource for the Electric System. The process of decommissioning the nuclear power plant is expected to take many years and is governed by Nuclear Regulatory Commission (the “NRC”) regulations. According to the 2024 Decommissioning Cost Estimate provided by SCE, the total decommissioning costs for Units 2 and 3 are estimated at \$5.7 billion in 2023 dollars, of which the Electric System’s share is approximately \$102.6 million. The Electric System has established trust accounts and a designated decommissioning reserve to accumulate resources for the decommissioning process. As of June 30, 2025, the Electric System has paid \$55.6 million for its share of the decommissioning costs from the trust accounts. The remaining estimated costs of \$47.0 million are expected to be fully covered by the trust accounts and the designated decommissioning reserve, which as of June 30, 2025, had values of \$41.5 million and \$12.2 million, respectively. Because of the uncertainty of future unknown costs, the Electric System will continue to set aside moneys in the designated decommissioning reserve in the amount of \$1 million per year (as decreased beginning in Fiscal Year 2024-25). The \$1 million amount has been approved by the Board and City Council and will be set aside each year unless adjusted by the Board and City Council in the future.

Fuel Supply/Procurement. The City’s RERC, Springs and Clearwater generating plants are fueled by natural gas. The City procures natural gas from credit-approved counterparties for its natural gas generation plants on a monthly and daily basis. Historically, the summer months have been the City’s primary focus for natural gas procurement as the City has reliability requirements to run internal generation during high load days. Additionally, natural gas procurement is needed when it is determined to be more economical to run internal generation than to buy from the CAISO energy markets. Finally, natural gas procurement is needed for City-owned generation to meet resource adequacy obligations and to meet local reliability needs of the City during significant line outages or system emergencies that can occur.

Entitlements

IPP Generating Station. The City has a 7.617% (approximately 137.1 MW) entitlement in the coal-fired IPP Generating Station Units 1 and 2 located near Lynndyl, Utah, which were declared to be commercially operational in June 1986 and May 1987, respectively. The City has entered into a power sales agreement with IPA, as the owner of IPP, which obligates the City to purchase its share of capacity

and energy of IPP on a take-or-pay basis (the “IPP Contract”). The IPP Contract expires in 2027. See the caption “—Indebtedness; Joint Powers Agency Obligations.” After 2027, the City expects to replace most of the power that is currently supplied through the IPP Contract with energy from new renewable resources, concurrent with its efforts to reach a 60% renewable portfolio standard by or before 2030. See the captions “—Electric System Strategic Plan—Power Resource Portfolio Management” and “—State Legislation Affecting the Power Supply.”

IPP consists of: (a) two coal-fired, steam-electric generating units with net ratings of 900 MW each and a switchyard located near Lynndyl, Utah; (b) a rail car service center located in Springville, Utah; (c) certain water rights; and (d) certain transmission facilities consisting primarily of the Southern Transmission System (“STS”). See the caption “—Transmission and Distribution Facilities—Southern Transmission System.”

There are 35 utilities that purchase the output of IPP, consisting of the City, and the California cities of Los Angeles, Anaheim, Burbank, Glendale and Pasadena, 23 members of IPA and six rural electric cooperatives serving loads in the States of Utah, Arizona, Colorado, Nevada and Wyoming. IPP is operated by the City of Los Angeles, through its Department of Water and Power (“LADWP”).

The IPP Generating Station’s annual coal requirement is approximately 900,000 tons in calendar year 2025. LADWP, in its role as the operating agent of IPP, buys coal under contracts to fulfill this supply requirement of IPP. 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 IPP 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 IPP 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.

Under Senate Bill 1368, the City is precluded from renewing the IPP Contract at the end of its term in June 2027. See the captions “—State Legislation Affecting the Power Supply—Senate Bill 1368 – Emission Performance Standard” and “—Electric System Strategic Plan—Power Resource Portfolio Management.” However, certain other parties could continue their participation.

In order to facilitate continued participation in IPP, the IPA Board of Directors issued the Second Amendatory Power Sales Contract, which amended the IPP Contract to allow the plant to replace the coal units with combined cycle natural gas units by July 1, 2025. IPA and purchasers representing 100% of IPA’s generation entitlement share completed and executed the Renewal Power Sales Contract, which will allow such participants to continue taking power from IPP, fueled initially by natural gas, for the period from 2027 through 2077. After extensive discussions among IPA and the IPP participants, it was determined that the participants’ demand would not support the current design capacity of the currently, contractually obligated repowering plan (the “IPP Repower Project”) of 1,200 MWs. As a result, the IPP Coordinating Committee, the IPP Renewal Contract Coordinating Committee and the IPA Board of Directors concluded that it was in the best interest of the participants to downsize the future IPP Repower Project from 1,200 MW to 840 MW, and to redesign the power block. Such reduction in MWs and the change in configuration would be considered an “Alternative Repowering” under the Second Amendatory Power Sales Contract. On September 11, 2018, the City Council approved an “Alternative Repowering”

for IPP and the amendments to the Second Amendatory Power Sales Contract and the Renewal Power Sales Contract. The City's entitlement share in the Alternative Repowering Project is 4.167% (35 MW).

Under provisions of the Renewal Power Sales Contract, certain California participants, including the City, had the right to exit completely from the IPP Repower Project or any Alternative Repowering by providing a written notice of termination to IPA at least 90 days prior to November 1, 2019. On May 7, 2019, the City Council authorized: (i) termination of the Renewal Power Sales Contract between IPA and the Electric System effective November 1, 2019; and (ii) the Electric System's exit from the IPP Repower Project upon the expiration date of the current Power Sales Contract on June 15, 2027.

Hoover Power Plant. The Hoover Power Plant is located on the Arizona-Nevada border approximately 25 miles east of Las Vegas, Nevada, and is owned and operated by the U.S. Department of the Interior's Bureau of Reclamation (the "Bureau"). The power from the project is marketed by the Western Area Power Administration ("Western"). The City has executed agreements with the Bureau and Western which became effective on October 1, 2017 and expire on September 30, 2067. The City's entitlement is approximately 30 MW (1.461% of the total project); however, due to low lake levels resulting from prolonged drought conditions, the City's available capacity entitlement has been reduced to approximately 20.5 MW as of June 30, 2025.

PVNGS. The City has a 5.4% (12 MW) entitlement interest in the Authority's 5.91% ownership interest in PVNGS, including certain associated facilities and contractual rights, 5.44% ownership in the Arizona Nuclear Power Project High Voltage Switchyard and associated contractual rights and 6.55% share of the rights to use certain portions of the Arizona Nuclear Power Project Valley Transmission System. The City has entered into a power sales agreement with the Authority that obligates the City to purchase its share of capacity and energy on a take-or-pay basis.

PVNGS consists of three nearly identical nuclear electric generating units located on an approximately 4,000-acre site about 50 miles west of Phoenix, Arizona. Units 1, 2 and 3 (each designed for a 40-year life) achieved firm operation on January 27, 1986, September 18, 1986, and January 19, 1988, respectively.

Units 1, 2 and 3 each operate under a 40-year Full-Power Operating License from the NRC. The Full-Power Operating Licenses for Units 1, 2 and 3 expire in 2025, 2026 and 2027, respectively. In April 2011, the NRC approved 20-year license extensions for all three units, allowing the three units to extend operations until 2045, 2046 and 2047, respectively. The Authority has informed the City that all other permits, licenses and approvals necessary to operate PVNGS have been secured. Arizona Public Service Company ("APS") is the Construction Manager and Operating Agent of PVNGS and the Westwing 500 kilovolt ("kV") Switchyard. The high-voltage switchyard portion of the PVNGS was constructed, and is being managed, by Salt River Project Agricultural Improvement and Power District.

The co-owners of PVNGS have created external accounts for the decommissioning of PVNGS at the end of its life. The Authority's records indicate that the aggregate balance of the external accounts for decommissioning was approximately \$199 million as of June 30, 2025. Based on the most recent estimate of decommissioning costs prepared by TLG Engineering in 2023, the Authority has advised the City that it estimates that the City's share of the amount required for decommissioning was 82% funded as of December 31, 2024, slightly under the 83% committed funding level but well above the 67% floor funding level. The Authority is continually assessing whether additional funding is needed to meet the committed funding level. No assurance can be given, however, that the required funding level will be sufficient to fully fund the Authority's share of decommissioning costs at license expiration and commencement of decommissioning activities.

APS currently stores spent nuclear fuel in on-site pools near the generating units. The pools have reached capacity, and additional on-site spent fuel storage has been used until a permanent repository for

high-level nuclear waste developed by the federal government becomes available. The additional onsite spent fuel storage has been provided by an independent spent fuel storage installation. The installation uses dry cask storage similar to that being used at other nuclear plants, such as SONGS, and is designed to accept all spent fuel generated by PVNGS during its lifetime.

APS ships all of its low-level radioactive waste to available disposal sites in Utah and South Carolina. In August 1995, a storage facility for low-level radioactive materials was opened at PVNGS to allow temporary on-site storage in case the disposal sites are not available. APS estimates that the storage facility has sufficient storage capacity to store all low-level radioactive waste produced at PVNGS until the end of operations. This on-site storage facility remains fully available.

Renewable Resources

In an effort to increase the share of renewable energy sources in the City’s power portfolio, the City entered into power purchase agreements (“PPAs”) and power sales agreements (“PSAs”) with various entities described below in general on a “take-and-pay” basis. The contracts in the following tables were executed as part of compliance with Renewable Portfolio Standards mandates.

**Table 5
Long-term renewable PPAs and PSAs in operation:**

<u>Supplier</u>	<u>Type</u>	<u>Maximum Contract Amount⁽¹⁾</u>	<u>Contract Expiration</u>
CalEnergy – Salton Sea Portfolio	Geothermal	86.0 MW	12/31/2039
Atlantica – Coso Geothermal ⁽²⁾	Geothermal	10.0 MW	12/31/2041
WKN Wagner	Wind	6.0 MW	12/22/2032
Terraform Power – AP North Lake	Photovoltaic	20.0 MW	08/11/2040
Onward Energy – Columbia II	Photovoltaic	11.1 MW	12/22/2034
Salka Cabazon Wind, LLC	Wind	39.0 MW	12/31/2027
Arevon – Kingbird Solar B, LLC	Photovoltaic	14.0 MW	12/31/2036
AES			
Summer Solar	Photovoltaic	10.0 MW	12/31/2041
Antelope Big Sky Ranch	Photovoltaic	10.0 MW	12/31/2041
Antelope DSR 1 Solar	Photovoltaic	25.0 MW	12/19/2036
Arevon – Tequesquite Landfill Solar	Photovoltaic	7.3 MW	12/31/2040
Roseburg Forest Products	Biomass	N/A ⁽³⁾	02/16/2026
Total		<u>238.4 MW⁽⁴⁾</u>	

⁽¹⁾ All contracts are contingent on energy delivered from specific related generating facilities. The City has no commitment to pay any amounts except for energy delivered on a monthly basis from these facilities except for any economic curtailments directed by the Riverside Public Utilities Department.

⁽²⁾ An additional 20 MW for Atlantica’s Coso Geothermal project is expected to be delivered by March 31, 2026, but no later than March 31, 2027.

⁽³⁾ This supply is only available to satisfy SB 859 requirements.

⁽⁴⁾ An additional 125 MW from SunZia Wind Power Co., LLC is expected to be delivered no later than March 31, 2027.

Salton Sea. On May 20, 2003, the City and Salton Sea Power LLC (“Salton Sea”) entered into a ten-year PPA for 20 MW of geothermal energy (the “Salton Sea PPA”). On August 23, 2005, the City Council approved an amendment to the PPA that increased the amount of renewable energy available to the City from 20 MW to 46 MW effective June 1, 2009 through May 31, 2020.

On May 14, 2013, the City Council approved a new 25-year PPA with CalEnergy, the parent of Salton Sea, for additional renewable geothermal power (the “CalEnergy PPA”). The CalEnergy PPA

commenced in February 2016. Under the CalEnergy PPA, power is provided from a portfolio of ten geothermal generating units instead of a single generating unit, with an increasing amount of delivery that started at 20 MW in 2016, increased to 40 MW in 2019 and increased to 86 MW in 2020. The initial price under the agreement was \$72.85 per MWh in calendar year 2016, which will escalate at 1.5% annually for the remaining term of the agreement. Like other renewable PPAs, the Riverside Public Utilities Department is only obligated to pay for energy that is delivered to the City.

Concurrently, the pricing under the Salton Sea PPA was amended to conform to the pricing under the CalEnergy PPA through the remaining term of the Salton Sea PPA. The pricing under the Salton Sea PPA increased by approximately \$7.57 per MWh, commencing July 1, 2013, to \$69.66 per MWh, with an escalation of 1.5% annually thereafter, reflecting the exchange of benefits for a substantially lower pricing under the new PPA. The cost increase under the Salton Sea PPA and accrual of the prepayment ended as of May 31, 2020. As of June 30, 2025 and 2024, the Electric System's prepayment of future contractual obligations was \$11,174,000 and \$11,689,000, respectively. This prepayment is recorded on the Statements of Net Position as unamortized purchased power, to be amortized over the term of the CalEnergy PPA. As of June 30, 2025 and 2024, the Electric System has recorded \$515,000 and \$641,000, respectively, in amortization related to the unamortized purchased power.

Atlantica – Coso Geothermal. On January 15, 2021, the City entered into a 20-year PSA with the Authority for 10 MW for the first five years of the contract and 30 MW for the remaining 15 years of the contract of geothermal energy generated by Atlantica's Coso Geothermal project. The City has partnered with the Cities of Banning and Pasadena to share the Authority's contracted capacity in this project. The project began delivering power on January 1, 2022. The City's share of Coso Geothermal is expected to provide 87,500 MWh annually in the first five years of the term and 268,300 MWh for the remainder of the term at an all-in price for energy, capacity, resource adequacy, and environmental attributes of \$69.00 per MWh over the term of the PSA.

WKN Wagner. On December 20, 2012, the City entered into a 20-year PPA with WKN Wagner, LLC ("WKN") for up to 6 MW of renewable wind energy and renewable energy credits from the WKN Wagner wind project in Palm Springs, California. WKN is expected to generate 21,000 MWh of renewable energy annually at a levelized cost of \$73 per MWh.

Terraform Power – AP North Lake. On October 16, 2012, the City entered into a 25-year PPA with AP North Lake, LLC ("AP North") for 20 MW of solar photovoltaic ("PV") energy generated by a new facility located in the City of Hemet, California. The AP North Lake Project became fully operational in August 2015. The project is expected to generate 55,000 MWh of renewable energy per year at a levelized cost of \$95 per MWh for the term of the PPA. After a series of ownership changes, AP North Lake is now owned by Terraform Power.

Onward Energy – Columbia II. On September 19, 2013, the City entered into a 20-year PSA with the Authority for 11.1 MW of solar PV energy generated by a facility to be built by Recurrent Energy in Kern County, California. The project, referred to as Columbia Two Solar Photovoltaic Project, has a nameplate capacity of 15 MW. On March 14, 2014, a Consent and Agreement was entered into by the Authority consenting to the transfer of ownership of the Columbia Two project from Recurrent Energy to Dominion Resources. The Columbia Two Project completed construction and achieved commercial operation in December 2014. The City has a 74.3% share (11.1 MW) of the output from the Columbia Two Project through the Authority, which has a 15 MW PPA with Dominion Resources. The City's share of Columbia Two is approximately 33,000 MWh of renewable energy per year with an all-in price for energy, capacity and environmental attributes of \$69.98 per MWh over the term of the agreement. In 2021, Onward Energy, LLC became the new parent company of Columbia Two.

Salka Cabazon Wind, LLC. On December 6, 2013, the City and FPL Energy Cabazon Wind, LLC ("Cabazon Wind") entered into a 10-year PPA for 39 MW of renewable wind energy from the Cabazon

Wind Energy Center near Cabazon, California. Cabazon Wind is an existing renewable resource that has been in commercial operation since 1999. SCE purchased the output of the facility through December 2014. At the expiration of SCE's contract, Cabazon Wind entered into new interconnection and generation agreements with CAISO and SCE. The developer completed the implementation of the transition to the City as of January 1, 2015. Delivery under the PPA commenced on January 1, 2015. The project is expected to generate 71,200 MWh of renewable energy per year with an all-in price for energy, capacity and environmental attributes of \$59.30 per MWh over the term of the agreement. In 2018, after it was acquired by GlidePath Power Solutions, FPL Energy Cabazon Wind, LLC changed its name to GPS Cabazon Wind, LLC. On September 1, 2023, Salka Cabazon HoldCo LLC purchased the GPS Cabazon Wind project and assumed the remaining term of the Agreement.

Arevon – Kingbird Solar B, LLC. On September 19, 2013, the City entered into a 20-year PSA with the Authority for 14 MW of solar PV energy generated by a facility to be built by First Solar in Kern County, California. The project is referred to as the Kingbird B Solar Photovoltaic Project, with a nameplate capacity of 20 MW. The City has a 70% share of the output from the project through the Authority, who has a 20 MW PPA with Kingbird Solar B, LLC, which was acquired by Capital Dynamics in 2018. The project became commercially operational on April 30, 2016. The City's share from the project is approximately 35,000 MWh of renewable energy per year with an all-in price for energy, capacity and environmental attributes of \$68.75 per MWh over the term of the agreement. In 2022, Capital Dynamics was acquired by Arevon.

AES – Summer Solar, Antelope Big Sky Ranch and DSR 1 Solar. On January 17, 2013, the City entered into two 25-year PSAs with the Authority for a combined total of 20 MW of solar PV energy generated by two facilities to be built in the City of Lancaster by Silverado Power, which later changed its name to sPower after a series of ownership changes. The two projects are referred to as Antelope Big Sky Ranch and Summer Solar, and each is rated at 20 MW. The City has a 50% share of the output from each project through the Authority, which has two 20 MW PPAs for the projects. Summer Solar became commercially operational on July 25, 2016, and Antelope Big Sky Ranch became commercially operational on August 19, 2016. The City's share from the two projects totals 55,000 MWh of renewable energy per year. The price under the agreements is \$71.25 per MWh over the term of the agreements. In 2021, sPower merged with the AES Corporation resulting in AES becoming the new parent company.

On July 16, 2015, the City entered into a 20-year PSA with the Authority for 25 MW of solar PV energy generated by AES's Antelope DSR Solar 1 PV Project in the City of Lancaster, California. The City has a 50% share of the output from the project through the Authority, which has a 50 MW PPA with AES. The project became commercially operational on December 20, 2016. The City's share of Antelope DSR 1 Solar is expected to generate approximately 71,000 MWh of renewable energy per year with an all-in price for energy, capacity and environmental attributes of \$53.75 per MWh over the term of the agreement.

Arevon – Tequesquite Landfill Solar. On March 11, 2014, the City and Solar Star California XXXI, LLC ("Solar Star") entered into a 25-year PPA for 7.3 MW of solar PV energy generated by a facility to be built on the City-owned Tequesquite Landfill. The project was fully commissioned and operational on September 30, 2015 and is expected to generate approximately 15,000 MWh of renewable energy per year. The all-in price for energy, capacity and environmental attributes was initially \$81.30 per MWh, escalating at 1.5% annually. In 2018, Capital Dynamics became the new parent company of Solar Star after acquiring it from SunPower. In 2022, Capital Dynamics was acquired by Arevon.

Roseburg Forest Products. On February 16, 2021, the City entered into a 5-year SB 859 Purchase Agreement with Roseburg Forest Products Co for the remaining 0.5 MW of SB 859 compliance. The City has a 4.48% share of the output of the project along with the Authority, Modesto Irrigation District, Sacramento Municipal Utility District, and Turlock Irrigation District, for a total capacity of 11 MW with

Roseburg. The project began delivery on February 16, 2021. The price for the SB 859 compliant capacity is \$46.00 per MWh over the term of the agreement.

SunZia Wind Power Co. In addition to the agreements that are described in Table 5 above with respect to projects that are currently in operation, on November 8, 2023, the City entered into a 15-year Renewable Power Purchase and Sale Agreement with SunZia Wind Power Co., LLC for 125 MW from the wind-powered electricity generating facility located in New Mexico. The facility is expected to provide an additional 369,000 to 390,000 MWh per year of long-term renewable energy to Riverside. The facility will provide energy, capacity, resource adequacy, and environmental attributes at an all-in price of \$59.50 per MWh throughout the term of the agreement. The project is expected to begin delivery by March 31, 2026 with an enforceable guaranteed delivery date of September 30, 2026.

Firm Contracts and Market Purchases

The City supplements the energy available from its firm resources with energy purchased from other suppliers throughout the western United States, as well as the CAISO Integrated Forward Market and real time market. These purchases are made under the Western Systems Power Pool (“WSPP”) Agreement and numerous short-term bilateral agreements between the City and various suppliers. Energy purchases in the CAISO markets are made under the FERC-approved CAISO Tariff.

In Fiscal Years 2024-25 and 2023-24, the City purchased 711,300 MWh and 786,800 MWh, respectively, of firm energy (approximately 31.4% and 35.7%, respectively, of its total energy supply) through short-term contracts. These purchases were from WSPP counterparties, with energy ultimately being served through the CAISO Integrated Forward Market. The cost of obtaining the necessary energy depends upon contract requirements and the current market price for energy. Spot market prices are dependent upon such factors as natural gas prices, the availability of generating resources in the region, fuel type and weather conditions such as ambient temperatures and the amount of rainfall or snowfall. Generating unit outages, dry weather, hot or cold temperatures, time of year, transmission constraints and other factors can all affect the supply and price of energy.

Wholesale Power Trading Policies and Risk Management.

In October 1998, the City Council adopted formal policies for the administration of energy risk management activities within the Power Resources Division of the Electric System. These policies define the limits for power trading activities to mitigate and reduce risks associated with this business activity. Riverside also appointed an Energy Risk Manager in 1999 to oversee the development, implementation, and ongoing monitoring of a formalized financial risk management program for power supply activities. Since 1998, the policies have been reviewed on an annual basis and recommended changes have been periodically adopted by the City Council.

The policies incorporate changes in regulatory and legislative requirements, including an amendment to authorized transactions, organizational structure, and reporting requirements. The comprehensive updated policies were approved by the Riverside Board and City Council on February 1, 2013 and March 5, 2013, respectively, and include an Energy Risk Management Policy, a Wholesale Counterparty Risk Management Policy and an Authorized Transactions Policy. The Wholesale Counterparty Risk Management Policy was amended for non-substantive changes on April 29, 2014.

California Independent System Operator

Riverside serves as its own Scheduling Coordinator with the CAISO and serves as the scheduling agent, under separate Utility Service Agreements, for the Cities of Banning and Rancho Cucamonga. In addition, Riverside serves as the scheduling agent for the Authority’s Columbia II Solar, Kingbird B Solar, Summer Solar and Antelope DSR 1 Solar projects under various Scheduling Coordinator Agreements.

Services under the referenced agreements include day-ahead and real time scheduling of power from various sources, after-the-fact validation and settlement of transactions, and billing and payments.

On July 10, 2002, Riverside notified the CAISO of its intent to become a Participating Transmission Owner (“PTO”) by turning over operational control of Riverside’s transmission entitlements (the “CAISO-Transferred Entitlements”) to the CAISO effective January 1, 2003. In November 2002, Riverside executed the Transmission Control Agreement (“TCA”) between the CAISO and the PTOs.

Certain of Riverside’s CAISO-Transferred Entitlements relate to transmission facilities, including STS, which were financed by the Authority utilizing tax-exempt bonds (the “Authority’s Bonds”). Riverside executed certain transmission service contracts with the Authority that prohibit Riverside from taking any action that would adversely affect the tax-exempt status of the Authority’s Bonds. If Riverside were to be found to have breached such contractual obligation, Riverside could be subjected to significant financial liability. The TCA executed by Riverside and submitted by the CAISO on November 19, 2002 for approval by the Federal Energy Regulatory Commission (“FERC”) contained certain withdrawal provisions which Riverside believes will protect the tax-exempt status of the Authority’s Bonds and satisfy Riverside’s contractual obligation to the Authority under its transmission service contracts. To date, the Authority has received no notices affecting the tax-exempt status of the Authority’s Bonds issued for projects in which the City is a participant.

On January 1, 2003, Riverside became a PTO with the CAISO, entitling Riverside to receive compensation for the use of its transmission entitlements committed to the CAISO’s operational control. The amount of compensation to which Riverside is entitled is based upon Riverside’s Transmission Revenue Requirement (“TRR”) as approved by FERC. Included in Riverside’s TRR are all costs associated with Riverside’s participation in the Authority’s transmission projects (STS and Mead-Adelanto and Mead-Phoenix transmission projects). Riverside obtains all of its transmission entitlements from the CAISO.

Since becoming a PTO with the CAISO, Riverside has filed three TRR’s with FERC. Riverside’s base TRR is adjusted annually for (among other things) automatic pass throughs of certain costs approved by FERC. For Fiscal Year ended June 30, 2025, Riverside collected \$32.7 million in TRR revenue.

Transmission and Distribution Facilities

The paragraphs that follow describe the City’s transmission facilities and entitlements and distribution facilities.

Southern Transmission System. STS is one of three major components of IPP. In connection with its entitlement to IPP, the City assigned its entitlement to capacity of STS to the Authority, in exchange for which the Authority agreed to make payments-in-aid of construction of STS and issued revenue bonds to finance the costs thereof. Pursuant to a transmission service contract with the Authority, the City acquired a 10.2% (195 MW) entitlement in the Authority’s share of the transfer capability of STS. The City’s contractual entitlement extends until June 2027. See the caption “—Indebtedness; Joint Powers Agency Obligations.” Among other things, STS provides for the transmission of energy from IPP to the California transmission grid.

The STS consists of the following: (a) the AC/DC Intermountain Converter Station adjacent to the IPP Generating Station’s AC switchyard in Utah; (b) the ±500-kV DC bi-pole transmission line (the “HVDC transmission line”), which is 488 miles in length, from the Intermountain Converter Station to the City of Adelanto, California; (c) the AC/DC Adelanto Converter Station, where STS connects to the switching and transmission facilities of LADWP; and (d) related microwave communication system facilities. The HVDC transmission line is capable of transmitting an amount of power that exceeds the aggregate output of the IPP Generating Station to be delivered to the Authority participants. The AC/DC converter stations each consist of two solid state converter valve groups and have a combined rating of

2,400 MW (upgraded from 1,920 MW in 2011, increasing the City's total entitlement in STS from 195 MW to 244 MW). The microwave communication facilities are used for IPP Generating Station dispatch, communication and control and protection of STS. The microwave facilities are located along two routes between the IPP Generating Station and the Adelanto Switching Station, forming a looped network.

Pursuant to the City's transmission service contract with the Authority, the City is obligated to pay as an Operating and Maintenance Expense its share of debt service on bonds issued by the Authority in connection with STS on a take-or-pay basis, as well as capital costs and costs related to operation and maintenance. See the caption "—Indebtedness; Joint Powers Agency Obligations."

Mead-Phoenix Transmission Project. Originally in connection with its entitlement to PVNGS power, the City acquired a 4.0% (12 MW) entitlement in the Authority's member-related ownership share of the Mead-Phoenix Transmission Project ("Mead-Phoenix"), which is separate from the Authority interest acquired on behalf of Western and the Authority interest later acquired on behalf of LADWP only. The City has entered into a transmission service contract with the Authority that obligates the City to pay as an Operating and Maintenance Expense its share of debt service on bonds issued by the Authority in connection with the Authority member-related interest in Mead-Phoenix on a take-or-pay basis, as well as capital costs and costs related to operation and maintenance. See the caption "—Indebtedness; Joint Powers Agency Obligations."

Mead-Phoenix consists of 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. The line is looped through the 500-kV switchyard constructed at Western's existing Mead Substation in southern Nevada with transfer capability of 1,923 MW (as a result of upgrades completed in 2009, increasing the City's total entitlement in Mead-Phoenix from 12 MW to 18 MW). By connecting to Marketplace Substation, Mead-Phoenix interconnects with the Mead-Adelanto Transmission Project (as described below) and with the McCullough Substation. Mead-Phoenix is comprised of three project components. The Authority has executed an ownership agreement providing it with an 18.3077% member-related ownership share in the Westwing-Mead project component, a 17.7563% member-related ownership share in the Mead Substation project component and a 22.4082% member-related ownership share in the Mead-Marketplace project component. Other owners of the line are APS, Salt River Project and Startrans IO, L.L.C. ("Startrans"). The project entered commercial operation on May 15, 1996.

Mead-Adelanto Transmission Project. In connection with Mead-Phoenix, the City has acquired a 13.5% (118 MW) entitlement to the Authority's member-related ownership share of the Mead-Adelanto Transmission Project ("Mead-Adelanto"), which is separate from the Authority interest acquired on behalf of Western and the Authority interest later acquired on behalf of LADWP only. Mead-Adelanto consists of a 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. By connecting to Marketplace Substation, the line interconnects with Mead-Phoenix and the existing McCullough Substation in southern Nevada. The line has a transfer capability of 1,291 MW. The Authority has executed an ownership agreement providing it with a total of a 67.9167% member-related ownership share in the project. The other owner of the line is Startrans. The City has entered into a transmission service contract with the Authority that obligates the City to pay as an Operating and Maintenance Expense its share of debt service on bonds issued by the Authority in connection with Mead-Adelanto on a take-or-pay basis, as well as capital costs and costs related to operation and maintenance. See the caption "—Indebtedness; Joint Powers Agency Obligations." The project entered commercial operation on May 15, 1996, which coincided with the commencement of operations by Mead-Phoenix.

Sub-Transmission and Distribution

Power is supplied to Riverside through seven separate, 69,000-volt sub-transmission lines from a substation that is owned and operated by SCE. These lines are used for the sole purpose of delivering electric energy from SCE’s Vista Substation to the northerly limits of Riverside. Each of the 69,000-volt sub-transmission lines are then interconnected to the Riverside-owned and -operated 69,000-volt sub-transmission system at multiple substations.

As of June 30, 2025, Riverside had 99.2 circuit miles of sub-transmission and 1,383 circuit miles of distribution lines, of which approximately 873 circuit miles are underground. There are 16 substations, with a combined capacity of 1,465 million volt-amperes (“MVA”). Riverside is currently undertaking the Riverside Transmission Reliability Project (“RTRP”), a joint City-SCE project which includes the construction of a 230-69-kV transmission substation. RTRP will provide a second point of interconnection to the California transmission grid, and the addition of new 69-kV transmission lines to transmit power from the new substation and distribute energy to Riverside’s local distribution substations. The costs of the RTRP to date have been partially financed by electric system revenue bonds issued by the City in 2008 and 2010 and the City may elect to issue an additional series of electric revenue bonds in or about 2029 to finance further RTRP construction costs. In addition, on December 4, 2007, Riverside added a reliability charge to its electric rates to assist with funding Riverside’s portion of the costs of RTRP.

The California Public Utilities Commission (the “CPUC”) issued a final Subsequent Environmental Impact Report (the “SEIR”) on October 2, 2018, marking the completion of the CPUC’s California Environmental Quality Act review process.

Capital Improvement Program

As part of its biennial budget and planning process, Riverside prepared a five-year Electric System Capital Improvement Program (“CIP”) for Fiscal Years ending June 30, 2025 through June 30, 2029, totaling approximately \$339.0 million, subject to adjustment as project cost estimates change:

	Five-Year CIP⁽¹⁾ (Dollars in Millions) Fiscal Years 2025-2029
Overhead	\$52,797
Underground	74,722
Substation	83,674
Recurring/Obligation to Serve	88,542
System Automation	39,229
Total	<u>\$338,964</u>

⁽¹⁾ Excludes RTRP construction costs.

The five-year CIP is supported by the Electric System’s rate plan and addresses the need to replace and modernize the most vital portions of Riverside’s aging electric infrastructure. Overhead and underground projects include the rehabilitation and replacement of overhead equipment, such as poles, wires, transformers, and streetlights and underground equipment such as conduits and cables in order to improve the safety, efficiency and reliability of the electric system. Substation projects include improvements to neighborhood power stations to efficiently distribute power throughout the service area. Recurring projects relate to the Electric System’s obligation to serve new incoming load. System automation projects include projects for technology, security and system automation tools and applications to improve cyber security and overall efficiency. The five-year CIP is expected to be funded from proceeds of certain series of electric system revenue bonds issued by the City, with the balance to be funded by a combination of rates, reserves and other resources. On February 1, 2024, the City issued its Electric

Revenue Bonds, Issue of 2024A, and the City expects to issue additional series of electric system revenue bonds in 2027 (the “2027 Bonds”). The 2027 Bonds have not yet been approved by the City Council and there can be no assurance that they will be issued at the time that is currently contemplated.

Customers and Energy Sales

The following tables set forth the number of meters as of the Fiscal Year end and total energy sold during the periods presented.

Table 6
Riverside Electric System
Number of Meters

	Fiscal Year Ended June 30,				
	<u>2025</u>	<u>2024</u>	<u>2023</u>	<u>2022</u>	<u>2021</u>
Domestic	101,115	100,505	100,054	99,731	99,226
Commercial	12,371	12,245	12,026	11,922	11,817
Industrial	646	637	622	625	616
Other.....	48	49	49	50	52
Total – all classes	<u>114,180</u>	<u>113,436</u>	<u>112,751</u>	<u>112,328</u>	<u>111,711</u>

Table 7
Riverside Electric System
Energy Sold
(Millions of kWh)

	Fiscal Year Ended June 30,				
	<u>2025</u>	<u>2024</u>	<u>2023</u>	<u>2022</u>	<u>2021</u>
Domestic.....	781	710	786	759	783
Commercial	438	427	440	443	430
Industrial.....	927	916	920	923	891
Other.....	11	12	15	19	18
Wholesale Sales.....	0	0	14	2	0
Total kWh Sold ⁽¹⁾	<u>2,157</u>	<u>2,065</u>	<u>2,175</u>	<u>2,146</u>	<u>2,122</u>

⁽¹⁾ The difference between the total kWh generated and purchased and the total kWh sold is due to transmission and/or distribution system losses.

[This space intentionally left blank.]

Customer Concentration

The following table lists the Riverside Electric System’s top 10 customers for Fiscal Year 2024-25 by dollar amounts charged.

TABLE 8
Riverside Electric System
Top 10 Electric System Customers
Fiscal Year 2024-25⁽¹⁾
(Dollars in Thousands)

<i>Electric System Customer</i>	<i>Electric Charges⁽²⁾</i>	<i>Percent of Electric System Retail Revenues⁽²⁾</i>
Local University	\$14,940,624	3.78%
Local Government	10,685,366	2.70%
Local Government	9,625,651	2.43%
Local School District	7,186,605	1.82%
Corporation	5,142,851	1.30%
Corporation	4,606,243	1.16%
Hospital	4,390,005	1.11%
Corporation	4,165,626	1.05%
Local University	3,839,167	0.97%
Corporation	3,217,434	0.81%
Total	\$67,799,572	<u>17.13%</u>

⁽¹⁾ Figures above do not include public benefit surcharge of 2.85% pursuant to AB 1890.

⁽²⁾ Based on unaudited actual figures.

Source: City.

The City has a strong and diverse customer base with minimal exposure to customer concentration. Many of the Riverside Electric System’s industrial customers have loads under 500 kW. The Riverside Electric System’s ten largest customers provided approximately 17.13% of retail revenues of \$395.6 million for the Fiscal Year ended June 30, 2025, based on unaudited actual figures.

Electric Rates and Charges

Riverside is obligated by its City Charter and by the resolutions under which it has issued its Electric System Revenue Bonds to establish rates and collect charges in an amount sufficient to meet its operation and maintenance expenses and debt service requirements, with specified requirements as to priority and coverage. Electric rates are established by the Riverside Board and approved by the Riverside City Council. Electric rates are not subject to the general regulatory jurisdiction of the California Public Utilities Commission (“CPUC”) or any other state agency. The California Public Utilities Code contains certain provisions affecting all municipal utilities such as Riverside, including provisions for a public benefits charge under Assembly Bill 1890 (“AB 1890”). At this time, neither the CPUC nor any regulatory authority of the state nor FERC approves Riverside’s retail electric rates, although FERC does approve Riverside’s TRR included in the Transmission Access Charge collected from users of the CAISO transmission grid.

Although its rates are not subject to approval by any federal agency, Riverside is subject to certain ratemaking provisions of the federal Public Utility Regulatory Policies Act of 1978 (“PURPA”). PURPA requires state regulatory authorities and nonregulated electric utilities, including Riverside, to consider

certain ratemaking standards and to make certain determinations in connection therewith. Riverside believes that it is operating in compliance with PURPA.

In January 1998, Riverside began collecting a surcharge for public benefit programs on customer utility bills. This surcharge was mandated by State legislation (*i.e.*, AB 1890 and subsequent legislation) and is restricted to various socially beneficial programs and services.

As of January 1, 2025, the Riverside Electric System has 19 rate schedules in effect. Riverside does not provide free electric service.

A rate proposal was provided to the Board on June 12, 2023 and to the City Council on June 27, 2023, after the completion of a rate study dated June 9, 2023 by an independent third party consultant (the “Rate Study”). In July and August 2023, staff conducted a comprehensive community outreach effort to present and obtain feedback on the rate plan proposal. Outreach efforts included various community meetings hosted by Riverside as well as Riverside’s attendance at multiple neighborhood and business group meetings. After holding the required public hearing on August 28, 2023, the Board adopted and recommended that the City Council approve a five-year electric rate plan (the “2023 Rate Plan”) based on the Rate Study.

On September 19, 2023, the City Council adopted the 2023 Rate Plan, which includes rate increases that became effective on January 1, 2024, and are scheduled for each January 1 thereafter through January 1, 2028, inclusive. The system average rate increases that became effective were 7.0% on January 1, 2024 and 7.0% on January 1, 2025, and will be followed by system average rate increases of 7.0%, 2.0%, and 2.0%, scheduled to become effective on January 1, 2026, 2027, and 2028, respectively. Actual increases for individual customers will vary by customer class and usage level.

Historically, electric rates for Riverside’s customers have been lower than rates for SCE customers. Based on Riverside’s rates effective June 1, 2025, Riverside’s single-family residential customers with annual monthly average consumption of 600 kWh would pay an average of 62% higher rates if served by SCE (based on average SCE rates). Riverside cannot predict future rate actions with respect to SCE or other utilities.

[This space intentionally left blank.]

The following table sets forth the average billing price per kWh for the various customer classes during the five Fiscal Years shown.

Table 9
Riverside Electric System
Average Billing Price (Cents) Per Kilowatt-Hour⁽¹⁾
(Retail Sales)

	Fiscal Year Ended June 30,				
	<u>2025</u>	<u>2024</u>	<u>2023</u>	<u>2022</u>	<u>2021</u>
Residential	21.03	19.58	17.88	17.70	17.00
Commercial	18.99	18.23	17.53	17.10	17.00
Industrial	15.41	14.16	13.54	13.30	12.60
Other	47.09	44.13	35.78	26.50	26.70
System Averages	18.34	17.07	16.08	15.80	15.20

⁽¹⁾ Figures above do not include public benefit surcharge of 2.85% pursuant to AB 1890.

Billings and Collections

Electric System service charges are billed and collected on a monthly Statement of Municipal Services and combined with the charges of the City’s water, sewer and refuse utilities. The customer service, billing and collection operations are provided for all utilities by designated functions of the City’s Public Utilities, Public Works, Finance and Information Technology Departments, coordinated through the Riverside Public Utilities Department.

Bills are due and payable on presentation and become delinquent after 21 days. Although the City is not subject to the jurisdiction of the CPUC or other agencies, collection activities for the City substantially conform to the requirements of California Public Utilities Code Section 10010 and California Health and Safety Code Section 116908. Accounts that have not paid their bills by the delinquency date receive an urgent notice providing an additional 10 days to pay. If no payment is received, a notice is delivered by Utility Field Service staff 10 days prior to proposed discontinuance of service, and the customer is charged a \$21.50 notification fee. If payment is not received after 60 days, metered service (water and/or electric) may be turned off approximately 1 to 5 working days later. Before service is reinstated, the customer must pay the delinquent amount and a reconnection fee ranging between \$43.00 and \$80.50, and may be required to pay a customer deposit.

Riverside Public Utilities Department manages delinquencies of amounts billed for the City’s Electric System and water, sewer and refuse utilities. Delinquencies from inactive accounts are turned over to a collection agency 90 days after account closure/no activity.

Transfers to the General Fund of the City

Effective December 1, 1977, transfers to the General Fund of the City of surplus funds of the Electric System (after payment of Operating and Maintenance Expenses and debt service on Bonds) are limited by Article XII of the City Charter, as approved by the voters and adopted by the City Council on November 15, 1977. Such transfers are limited to 12 equal monthly installments during each Fiscal Year constituting a total amount not to exceed 11.5% of the Gross Operating Revenues, exclusive of any surcharges, for the last Fiscal Year ended and reported by an independent public auditor. The General Fund transfer is funded through the existing rate plan, thus requiring no additional rate adjustments.

The transfers to the General Fund of the City for Fiscal Years 2024-25 and 2023-24 were \$45.2 million and \$45.3 million, respectively.

See the caption “—Litigation” for a description of a recent court ruling holding that the General Fund transfer from the Electric System is not a cost of providing the service of the Electric System and violates Article XIII C of the State Constitution. In response to the ruling, the City Council placed a ballot measure, known as Measure C, on the November 2, 2021 ballot, seeking the approval of City voters to continue transfers of surplus Electric System revenues to the General Fund. Measure C was approved by City voters and the City intends to continue to transfer Electric System revenues to the General Fund.

Unrestricted Cash Reserves

On March 22, 2016, the City Council adopted the Riverside Public Utilities Cash Reserve Policy, which provided a defined level of unrestricted, undesignated and designated cash reserves in the Electric System for strategic purposes. This policy sets target minimum and maximum levels for the undesignated reserve to mitigate risk in the following categories: operations and maintenance, rate stabilization, capital expenditures and debt service. The undesignated reserve can be used for any lawful purpose and has not been designated for specific capital and operating purposes. On September 7, 2021, the Cash Reserve Policy was updated and approved by City Council to reflect updates to the designated decommissioning reserve for SONGS, minimum and maximum funding levels for undesignated reserve and other minor revisions. On August 6, 2024, the Cash Reserve Policy was updated and approved by City Council to reduce the annual funding to the San Onofre Nuclear Generating Station Additional Decommissioning Liability Reserve. On November 17, 2025, the updated Cash Reserve Policy was approved by the Board and on December 2, 2025, it was approved by the City Council. The policy was updated to establish the California Employers’ Pension Prefunding 115 Trust – Unfunded Accrued Liability reserve and to clarify certain existing policy definitions.

On February 1, 2022, Riverside entered into the \$35,000,000 Revolving Credit Facility, which provides additional flexibility and operating liquidity for the Electric System.

As of June 30, 2025, the undesignated Electric System reserve balance was \$152.6 million, which, combined with the amount available under the Revolving Credit Facility, is anticipated to be within the minimum and maximum guidelines as set forth in the policy.

Designated reserves are considered unrestricted assets and represent the portion of unrestricted reserves set aside for specific purposes determined by the Board and City Council. Designated reserves may be held for capital or operating purposes. Based on unaudited actual figures, the designated cash reserve balances as of June 30, 2025, are as follows (in thousands of dollars):

Additional Decommissioning Liability Reserve	\$12,226
Customer Deposits	6,042
Capital Repair and Replacement Reserve	2,406
Electric Reliability Reserve	95,418
Mission Square Improvement Reserve	3,408
Dark Fiber Reserve	4,767
Total ⁽¹⁾	\$124,267

⁽¹⁾ Reflects preliminary unaudited actual figures; subject to change. Final figures will be included as a component of unrestricted cash and cash equivalents in the Statements of Net Position in the Electric System’s audited financial statements for the Fiscal Year ended June 30, 2025.

Indebtedness; Joint Powers Agency Obligations

As of December 1, 2025, Riverside had outstanding approximately \$564.2 million aggregate principal amount of Electric System Revenue Bonds, which are payable from and secured by a pledge of and lien on net operating revenues of the Electric System, consisting of:

Table 10
Riverside Electric System
Outstanding Electric System Revenue Bonds
As of December 1, 2025

Issue	Principal Amount Outstanding
Electric Revenue Bonds, Issue of 2010A (Federally Taxable Build America Bonds – Direct Payment)	\$117,965
Refunding Electric Revenue Bonds, Issue of 2019A	210,730
Refunding Electric Revenue Bonds, Issue of 2023A	29,400
Electric Revenue Bonds, Issue of 2024A	206,105
Total	\$564,200

For the Fiscal Year ended June 30, 2025, Riverside’s annual debt service on the outstanding Electric System Revenue Bonds totaled approximately \$50.0 million. Assuming no further debt issuances, the annual debt service on such outstanding Electric System Revenue Bonds following June 30, 2025 will be at a high of approximately \$51.5 million in 2040, declining to a low of approximately \$11.7 million in 2050.

In addition, Riverside participates in certain contracts with Intermountain Power Agency (“IPA”) and the Authority. Obligations of Riverside under the agreements with IPA and the Authority constitute operating and maintenance expenses of Riverside payable prior to any of the payments required to be made on the Electric System Revenue Bonds and any parity debt. Agreements between Riverside and IPA and Riverside and the Authority are on a “take-or-pay” basis, which requires payments to be made whether or not applicable projects are completed or operable, or whether output from such projects is suspended, interrupted or terminated. All of these agreements contain “step-up” provisions obligating Riverside to pay a share of the obligations of a defaulting participant. Any “step-up” obligation relating to Riverside’s participation in transmission projects that it would be responsible for would be included in Riverside’s TRR (that would require filing a new TRR at the FERC) and would be recovered from all CAISO grid users. Riverside’s participation and share of principal obligation (without giving effect to any “step-up” provisions) for each of the joint powers agency projects in which it participates are shown in the following table. As of June 30, 2025, the City’s total debt service obligations with respect to joint powers agency bonds were approximately \$50.4 million. In certain cases, Riverside could become responsible for a greater share of debt service on joint powers agency bonds if other participants were to default on their respective obligations with respect to such bonds.

Table 11
Riverside Electric System
Outstanding Debt of Joint Powers Agencies
As of December 1, 2025

	Principal Amount of Outstanding Debt	Riverside Participation⁽¹⁾	Riverside Share of Principal Amount of Outstanding Debt
Intermountain Power Agency			
Intermountain Power Project ⁽²⁾	\$112,520,000	7.617%	\$3,101,902 ⁽³⁾
Southern California Public Power Authority			
Southern Transmission System ⁽⁴⁾	<u>72,190,000</u>	10.164	<u>7,337,392</u>
Total	\$184,710,000		\$10,439,294

(1) Participation obligation is subject to increase upon default of another project participant.

(2) The IPP Contract expires in 2027, after which time, Riverside will have no further obligations to pay IPA debt.

(3) Reflects net share of principal amount of outstanding debt after giving effect to amounts received from IPA's issuance of its Series K Notes in July 2025.

(4) The STS Contract expires in 2027, after which time, Riverside will have no further obligations to pay STS debt.

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. Moreover, in certain circumstances, the failure to reimburse draws on the liquidity agreements may result in the acceleration of scheduled payment of the principal of such variable rate joint powers agency obligations. In addition, swap agreements entered into by the joint powers agencies are subject to early termination under certain circumstances, in which event substantial payments could be required to be made to the applicable swap provider.

Insurance

The City's Risk Management Division manages the insurance needs of the City's Electric System. The City's Self-Insurance Trust Fund Reserve Policy requires that both the Liability and Worker's Compensation funds maintain cash on hand in the minimum amount equal to 50% of all outstanding claims. The fund balance amounts are based on annual actuarial studies on the City's automobile, general, and worker's compensation liability and internal claim data. The actuarial reports are issued by an outside firm.

The City carries multiple excess General Liability policies with a coverage limit of \$25,000,000 in combined General Liability coverage. The excess General Liability policies cover general and automobile liability claims, including but not limited to Law Enforcement Liability and Public Officials Errors and Omissions coverage. The City also purchases an excess Workers Compensation policy with an aggregate limit of \$25,000,000. The General Liability program has a self-insured retention of \$4,000,000 and the Worker's Compensation program has a self-insured retentions of \$3,000,000. A self-insured retention is the dollar amount that the City must pay before an insurance policy responds to a loss.

The City participates in two separate property insurance programs; the first is an "All Risk" property program that affords an aggregate limit of \$1.2 billion for City-owned properties, and the second program provides \$210 million in property and equipment breakdown coverage for RERC, Springs and Clearwater. The City also purchases a stand-alone Pollution policy for RERC, Springs and Clearwater. See the caption "—City-Owned Generating Facilities" for a discussion of RERC, Springs and Clearwater. The City's property deductibles range from between \$100,000 to \$250,000 depending on the peril at the time of loss. At the time of loss, valuation will be on a replacement cost basis with actual loss sustained for time element coverages and an actual cash value for all City-owned equipment.

The City does not currently maintain earthquake insurance on the Electric System's facilities.

Litigation

Parada II. On September 12, 2018, a petition for writ of mandate entitled *Parada v. City of Riverside* (Parada II) was filed against Riverside seeking to invalidate, rescind and void under Proposition 26 the Electric System's rates approved by City Council on May 22, 2018, which took effect on January 1, 2019, by challenging the portion of the electric rates that are attributable to the General Fund transfer. The petition did not seek any monetary relief from the General Fund. The trial court divided the case into two stages for hearings: a liability phase and a damages phase. On April 17, 2020, the Court in the liability phase of Parada II litigation entered a tentative ruling finding Riverside's electric rates attributable to the General Fund transfer violates Article XIII C of the California Constitution. The formal hearing on the matter took place on June 5, 2020, but the Court asked for further briefing on the issue of whether or not the plaintiffs failed to exhaust their administrative remedies. On October 9, 2020, the Court confirmed its tentative ruling and entered an order denying Riverside's request for interlocutory remand. The court had set a hearing for February 24, 2021, to set a briefing schedule for determining appropriate remedies/damages in the case. Riverside expected the second phase of the trial relating to plaintiffs' available remedies to occur in the second quarter of 2021.

The ruling by the Court in Parada II was anticipated to likely have a material adverse impact on Riverside's General Fund. The General Fund receives approximately \$40 million annually (up to the maximum amount of 11.5% of Electric Fund revenues) from the Electric Fund. Based on the Court's order in the liability phase of the trial, approximately \$19 to 32 million of the General Fund transfer is potentially attributable to rate payer revenue that was not approved by the voters. However, that amount will be determined during the damages phase of the trial. Additionally, Riverside might have been required to refund rate payers for the portions of the rates that were determined to violate Article XIII C of the California Constitution from the date the writ of mandate was filed. However, the trial court did not issue any ruling as to what the amount of any damages would be.

Based on the Court's order in the liability phase of the trial, Riverside estimated that the amount of a refund would be \$19 to \$32 million per year, beginning January 1, 2019, until date of settlement or issuance of a final, non-appealable judgment by the trial court after anticipated appeals are resolved. This amount could vary depending upon whether or not Riverside decides to repeal and replace the challenged rates pending appeal.

On May 17, 2021, Riverside and the plaintiffs entered into a settlement agreement that was conditioned on: (1) the City Council's placement of a ballot measure in the November 2021 election to approve the General Fund transfer as a general tax (the "Ballot Measure"); and (2) voter approval of the Ballot Measure. The City Council placed the Ballot Measure on the ballot for the November 2, 2021 election. The parties agreed to stay the litigation until certification of the results of the Ballot Measure. If voters approved the Ballot Measure, Riverside agreed to refund to Electric System customers an amount equal to \$24 million less the amount awarded to the plaintiffs' counsel in fees, paid over a five year period that was to begin no later than February 1, 2022. If voters did not approve the Ballot Measure, the litigation would then resume.

On or about September 16, 2021, prior to the November 2, 2021 election, a petition for writ of mandate entitled *Riversiders Against Increased Taxes v. City of Riverside, et al.* (the "RAIT lawsuit") was filed against Riverside challenging the Ballot Measure on the grounds that it could not be adopted at the November 2021 election because that election is a "special" election and, under Proposition 218, a ballot measure to impose a general tax can only be submitted to voters at a general election. On November 9, 2021, the court set a trial date for the RAIT lawsuit for January 7, 2022 and ordered a stay of the certification of the Ballot Measure election results pending the January 7, 2022 hearing. The court did not otherwise delay or cancel the election for the Ballot Measure, and the election was held on November 2, 2021, with Measure C approved by a majority of the voters.

On April 26, 2022 the RAIT lawsuit trial court determined that the November 2021 election was a “special election” rather than a “general election” and therefore did not comply with Proposition 218. The court further ruled that it lacked power to enjoin the certification of election results or to otherwise invalidate the election. Both sides have since appealed the April 26, 2022 ruling. On July 25, 2024, the appellate ruled in favor of Riverside and against RAIT, holding that Riverside conducted a proper election in compliance with Propositions 218 and 26.

On May 12, 2022, Riverside and the plaintiffs in the Parada II lawsuit amended the May 17, 2021 conditional settlement agreement to reflect the following additional terms: (a) Riverside agreed to start making refunds to ratepayers by October 1, 2022; (b) if Riverside prevailed in the appeal of the trial court’s decision in the RAIT lawsuit, no additional refunds would be due to the ratepayers; (c) if Riverside did not prevail in the appeal of the trial court’s decision in the RAIT lawsuit, additional refunds would be implemented in the amount of \$705,882 per month, from November 2021 until: (i) Riverside set new electric rates; (ii) voters approve a valid ballot measure relating to the General Fund transfer; or (iii) Riverside otherwise stops collecting the General Fund transfer from the Electric System. The Parada II lawsuit was dismissed on May 13, 2022.

The City Council adopted a resolution certifying the results of the Measure C election on July 19, 2022. The plaintiffs from the RAIT lawsuit sought to intervene in the Parada lawsuit and set aside this dismissal. On August 3, 2022, the Parada trial court refused to set aside the dismissal. The City has now begun to implement the settlement agreement. However, because the appellate court ruled in favor of the City, no additional refunds are owed to ratepayers by the City.

On July 25, 2024, the appellate court ruled in favor of the City and against RAIT, holding that the City conducted a proper election in compliance with Proposition 218 and 26. Because the appellate court ruled in favor of the City, no additional refunds are owed to ratepayers by the City under the Parada settlement agreement. On September 4, 2024, RAIT sought California Supreme Court review of the appellate decision and on October 30, 2024, the California Supreme Court declined review of the appellate court’s ruling in favor of the City.

Pending lawsuits and other claims against Riverside with respect to the Electric System are incidental to the ordinary course of operations of the Electric System and are largely covered by Riverside’s self-insurance program. In the opinion of the Electric System’s management and the City Attorney, such lawsuits (including the lawsuits discussed above) and claims will not have a materially adverse effect upon the financial position of the Electric System.

Summary of Operations

The following table prepared by Riverside shows the Net Operating Revenues of the Electric System for the five full Fiscal Years shown. The information shown is based on the audited financial statements of the City’s Electric System for such periods as well as preliminary unaudited results for Fiscal Year 2024-25, but excludes certain receipts which do not constitute Gross Operating Revenues and certain non-cash items and reflects certain other adjustments.

[This space intentionally left blank.]

Table 12
Riverside Electric System
Summary of Operations and Debt Service Coverage
(\$000's)

	Fiscal Year Ended June 30,				
	<u>2025*</u>	<u>2024</u>	<u>2023</u>	<u>2022</u>	<u>2021</u>
Operating Revenues⁽¹⁾:					
Residential	\$164,209	\$138,879	\$140,538	\$134,403	\$133,460
Commercial, Industrial and Other	231,406	213,623	206,953	203,474	188,947
Wholesale Sales	7	0	2,043 ⁽²⁾	89	27
Transmission Revenues	32,749	39,934	35,233	32,245	32,316
Other	33,948	26,089	24,403	18,758	12,099
Total Operating Revenues Before (Reserve)/Recovery	462,319	418,525	409,170	388,969	366,849
Reserve for Uncollectible, Net of (Reserve)/Recovery	(3,271)	(2,466)	(475)	681	(4,034)
Total Operating Revenues, Net of (Reserve)/Recovery	459,048	416,059	408,695	389,650	362,815
Interest Income/(Loss) ⁽³⁾	16,503	11,782	7,874	4,461	4,794
Capital Contributions	6,573	4,701	4,951	5,445	3,456
Non-Operating Revenues.....	4,334	4,024	6,343	7,094	6,897
Total Revenues.....	<u>\$486,458</u>	<u>\$436,566</u>	<u>\$427,863⁽⁴⁾</u>	<u>\$406,650⁽⁴⁾</u>	<u>\$377,962</u>
Operating and Maintenance Expenses⁽⁵⁾⁽⁶⁾:					
Nuclear Production ⁽⁷⁾	1,271	955	1,023	914	822
Production & Purchased Power ⁽⁸⁾	185,146	198,611 ⁽⁹⁾	194,891 ⁽⁹⁾	175,682	163,086
Transmission Expenses ⁽¹⁰⁾	54,284	54,248	68,052	65,996	59,770
Distribution Expenses	20,887	18,001	21,415	18,270	21,735
Customer Account Expenses	7,832	7,760	7,871	6,845	6,829
Customer Service Expenses	2,090	2,310	2,182	1,727	1,638
Administration & General Expenses ⁽¹¹⁾	25,557	23,812	18,908 ⁽¹²⁾	10,992 ⁽¹³⁾	12,046
Arbitrage Rebate ⁽¹⁴⁾	2,526	0	0	0	0
Clearing & Miscellaneous Expenses....	21,769	20,945	18,559	17,794	18,367
Total Operating and Maintenance Expenses	<u>\$321,362</u>	<u>\$326,642</u>	<u>\$332,901</u>	<u>\$298,220</u>	<u>\$284,293</u>
Net Operating Revenues Available for					
Debt Service and Depreciation	\$165,096	\$109,924	\$94,962	\$108,430	\$93,669
Debt Service Requirements on Electric System Revenue Bonds⁽¹⁵⁾	\$54,997	\$50,694	\$46,400	\$46,028	\$44,923
Debt Service Coverage Ratio	3.00x	2.17x	2.05x	2.36x	2.09x

* Reflects preliminary unaudited results; subject to change.

(1) Operating Revenues exclude restricted revenues generated from the public benefits charge under AB 1890.

(2) Increase in Fiscal Year 2022-23 reflects a transmission constraint, requiring the power that the City was scheduled to receive to be resold.

(3) Differs from audited financial statements because the above numbers exclude unrealized losses (and gains), consisting of market value adjustments to Electric System investments in accordance with GASB Statement No. 31, of \$4,298, \$14,791, \$1,922, \$(6,933) and \$(10,684) in Fiscal Years 2020-21 through 2024-25, respectively.

(4) Includes net revenue adjustments of \$134, \$247, \$304 and \$373 under GASB Statement No. 87 relating to leases for Fiscal Years 2021-22 through 2024-25, respectively. The City elected not to revise the beginning net position upon its adoption of GASB Statement No. 87 as of July 1, 2021.

(5) Operating and Maintenance Expenses exclude expenses incurred under the related program.

(FOOTNOTES CONTINUED ON FOLLOWING PAGE)

- (6) In accordance with City Resolution No. 17662, as amended and supplemented, the figures shown exclude contributions to City’s General Fund of \$39,899, \$39,436, \$42,326, \$45,289 and \$45,215 for Fiscal Years 2020-21 through 2024-25, respectively. Also excludes depreciation and amortization.
- (7) Nuclear Production reflects non-decommissioning expenses and changes to decommissioning liability related to SONGS.
- (8) Includes fuel expense for City-owned generating facilities and payments to IPA and the Authority, other than payments relating to transmission projects with the Authority (Southern Transmission System, Mead-Phoenix, and Mead-Adelanto).
- (9) Increase in Fiscal Year 2022-23 primarily due to exceptionally elevated winter natural gas prices, which in turn caused significantly elevated power prices. Such power prices were already higher due to the Ukraine/Russia war which commenced in early 2022, which caused price disturbances in both the gas and power markets. Increase in Fiscal Year 2023-24 due to fuel restrictions on Intermountain Power Project coal resource throughout the fiscal year that forced Riverside Public Utilities Department to forward hedge significantly more energy.
- (10) Includes payments relating to transmission projects with the Authority (Southern Transmission System, Mead-Phoenix and Mead-Adelanto).
- (11) Excludes Governmental Accounting Standards Board (“GASB”) Statement No. 68, Accounting and Financial Reporting for Pension non-cash adjustments of \$9,682, \$(16,425), \$(1,308), \$7,707 and \$9,584 for Fiscal Years 2020-21 through 2024-25, respectively. Excludes GASB Statement No. 75, Accounting and Financial Reporting for Post-Employment Benefits Other Than Pensions non-cash adjustments of \$183, \$530, \$431, \$474 and \$526 for Fiscal Years 2020-21 through 2024-25, respectively.
- (12) Increase reflects one-time employee stipend (not qualifying for the purpose of pension compensation) approved by the City Council on September 20, 2022.
- (13) Decrease reflects non-cash pension accounting standard adjustment.
- (14) Beginning Fiscal Year 2024-25, Arbitrage Rebate funds were classified individually apart from the Electric Revenue Bonds, Issue of 2024A in a separate account held at fiscal agent.
- (15) Includes debt service on a portion of the City’s pension obligation bonds issued in June 2020 that is attributable to the Electric System. Notwithstanding the inclusion of debt service in the table, such amounts are payable from moneys remaining after payment of Electric System Revenue Bonds.

[This space intentionally left blank.]

The following Statements of Net Position have been prepared by Riverside for the five full Fiscal Years shown. The information for the Fiscal Years ended June 30, 2021 through June 30, 2023 is based on the audited financial statements of the City's Electric System for such periods. The information for the Fiscal Year ended June 30, 2024 is revised due to a prior years adjustment and is pending re-certification. The information for the Fiscal Year ended June 30, 2025 is based on the preliminary, unaudited financial statements.

Table 13
Riverside Electric System
Electric Statements of Net Position (\$000)

	<u>Fiscal Year Ended June 30,</u>				
	<u>2025*</u>	<u>2024</u>	<u>2023</u>	<u>2022</u>	<u>2021</u>
Assets and Deferred Outflows of Resources					
Utility plant					
Production	267,280	\$265,966	\$265,966	\$269,814	\$269,248
Transmission	61,876	53,590	53,416	50,417	49,079
Distribution	796,271	752,595	741,877	725,159	706,807
General	128,069	124,700	122,127	123,432	117,696
Intangible	27,277	27,277	26,667	25,963	21,986
	<u>1,280,773</u>	<u>1,224,128</u>	<u>1,210,053</u>	<u>1,194,785</u>	<u>1,164,816</u>
Less accumulated depreciation	(634,570)	(600,577)	(564,436)	(535,466)	(503,088)
	646,203	623,551	645,617	659,319	661,728
Land					
Intangible, non-depreciating	56,528	56,436	56,386	53,042	53,042
Construction in progress	10,651	10,651	10,651	10,651	10,651
	83,421	84,543	72,262	72,724	72,481
Total utility plant	<u>796,803</u>	<u>775,181</u>	<u>784,916</u>	<u>795,736</u>	<u>797,902</u>
Lease and subscription assets ⁽⁶⁾	1,254	844	721	628	0
Less lease and subscription accumulated amortization ⁽⁶⁾	(587)	(434)	(316)	(137)	0
Total capital assets	<u>797,470</u>	<u>775,591</u>	<u>785,321</u>	<u>796,227</u>	<u>797,902</u>
Restricted assets ⁽¹⁾	246,231	267,768	133,151	118,828	125,738
Current assets:					
Cash and investments ⁽²⁾	276,817	258,200	247,831	274,172	287,294
Accounts receivable, net	56,786	41,805	37,260	50,093	43,785
Advances to other funds of the City	0	0	0	0	0
Accrued interest receivable	2,037	1,626	1,033	663	586
Leases receivable ⁽⁶⁾	1,478	1,343	1,359	990	0
Inventory	1,313	1,464	1,464	485	971

Prepaid expenses ⁽¹⁰⁾	9,321	3,859	6,168	6,127	6,964
Unamortized purchased power ⁽¹¹⁾	5,639	664	666	653	644
Total restricted and current assets	599,622	576,729	428,932	452,011	465,982
Other non-current assets:					
Advances to other funds of the City	1,098	1,555	2,003	2,454	2,925
Lease receivable ⁽⁶⁾	9,754	11,069	10,407	7,099	0
Net Pension Asset	0	0	0	26,219	0
Unamortized purchased power	12,598	11,025	11,664	12,317	12,971
Regulatory assets ⁽³⁾	1,999	2,109	1,573	1,665	1,757
Total other non-current assets	25,449	25,758	25,647	49,754	17,653
Deferred outflows of resources:					
Deferred outflows related to pension ⁽⁵⁾	28,534	31,018	34,931	9,168	15,820
Deferred outflows related to other post-employment benefits	1,284	1,498	1,592	1,805	2,167
Changes in derivative values ⁽⁸⁾	0	0	1,571	5,924	16,228
Loss on refunding	1,999	2,155	7,530	8,046	8,567
Total deferred outflows of resources	31,817	34,671	45,624	24,943	42,782
Total assets and deferred outflows of resources	1,454,358	\$1,412,749	\$1,285,524	\$1,322,935	\$1,324,319

Net Position, Liabilities and Deferred Inflows of Resources

Net position:					
Net investment in capital assets ⁽⁹⁾	239,920	\$229,507	\$254,224	\$246,097	\$237,501
Restricted for debt service	24,465	23,981	19,332	18,967	18,615
Restricted for regulatory requirements	41,762	34,261	25,502	19,598	16,923
Restricted for unfunded accrued liability ⁽⁷⁾	4,169	3,510	0	0	0
Restricted for public benefit programs	35,297	32,482	29,329	25,857	22,346
Unrestricted ⁽⁹⁾	214,943	184,420	174,965	195,044	201,988
Total net position	560,556	508,161	503,352	505,563	497,373
Long-term obligations, less current portion	686,221	712,106	590,602	615,834	639,791
Total net position and long-term obligations	1,246,777	1,220,267	1,093,954	1,121,397	1,137,164
Non-current liabilities:					
Compensated absences	4,383	2,065	1,889	2,426	3,389
Nuclear decommissioning	40,078	33,838	38,646	44,497	43,642
Other postemployment benefits liability/ payable	10,472	10,049	9,420	10,066	11,126
Net pension liability ⁽⁴⁾	52,907	44,227	38,748	0	39,233
Derivative instruments ⁽⁸⁾	0	0	4,097	8,905	19,968
Regulatory liability ⁽⁸⁾	0	0	4,675	4,220	3,461
Lease liability ⁽⁵⁾	383	162	225	363	0

SBITA liability ⁽⁵⁾	0	46	7	0	0
Total non-current liabilities	<u>108,223</u>	<u>90,387</u>	<u>97,707</u>	<u>70,477</u>	<u>120,819</u>
Current liabilities payable from restricted assets:					
Accrued interest payable	7,313	9,816	5,083	5,465	4,085
Nuclear decommissioning	6,887	12,244	10,227	8,813	7,254
Public benefit programs payable	1,026	750	866	624	239
Current portion of long-term obligations	<u>24,314</u>	<u>23,680</u>	<u>22,633</u>	<u>20,992</u>	<u>19,345</u>
Total current liabilities payable from restricted assets	<u>39,540</u>	<u>46,490</u>	<u>38,809</u>	<u>35,894</u>	<u>30,923</u>
Current liabilities:					
Accounts payable and other accrual	30,368	26,621	25,173	27,860	22,476
Unearned revenue ⁽¹¹⁾	4,244	762	314	1,412	67
Customer deposits	12,109	11,972	11,734	11,888	10,563
Other postemployment benefits liability/payable ⁽⁶⁾	335	397	417	394	0
Lease liability ⁽⁵⁾	190	132	137	134	0
SBITA liability ⁽⁵⁾	46	50	42	0	0
Total current liabilities	<u>47,292</u>	<u>39,934</u>	<u>37,817</u>	<u>41,688</u>	<u>33,106</u>
Deferred inflows of resources:					
Deferred inflows related to pension	312	1,892	3,577	44,089	1,714
Deferred inflows related to other postemployment benefits	1,990	2,038	2,266	1,426	593
Lease related items ⁽⁵⁾	<u>10,224</u>	<u>11,741</u>	<u>11,394</u>	<u>7,964</u>	<u>0</u>
Total deferred inflows of resources	<u>12,526</u>	<u>15,671</u>	<u>17,237</u>	<u>53,479</u>	<u>2,307</u>
Total net position, liabilities and deferred inflows of resources	<u>\$1,454,358</u>	<u>\$1,412,749</u>	<u>\$1,285,524</u>	<u>\$1,322,935</u>	<u>\$1,324,319</u>

* Reflects preliminary unaudited results; subject to change.

** Fiscal Year 2023-24 has been revised due to a prior period adjustment. Reflects revised unaudited results, subject to re-certification and audit opinion.

(1) Includes current and non-current restricted assets for historical comparison purposes. Increase in fiscal year 2023-24 includes the issuance of the Electric Revenue Bond, Issue of 2024A for new funding for qualifying electric capital projects.

(2) See discussion under "Unrestricted Cash Reserves" above.

(3) Riverside elected to record debt issuance costs and replacement power costs as regulatory assets which allows for deferring these expenses to be reflected in future rates.

(4) Decrease in Fiscal Year 2021-22 primarily due to the payment outflow of the 2020 Pension Obligation Bond Series A and the resulting decrease in net pension liability from the payment.

(5) Creation of these assets and liabilities resulted from the implementation of GASB Statement No. 87 *Leases* in the Fiscal Year ended June 30, 2022 and GASB Statement No. 96 *Subscription-Based Information Technology Arrangements* in the Fiscal Year ended June 30, 2023.

(6) For Fiscal Year 2020-21, current other postemployment benefits liability/payable is included in the non-current liabilities portion.

(7) Reflects restricted cash and investments held with a fiscal agent for the future payment of pension related costs.

(8) Decrease in Fiscal Year 2023-24 and onward due to the refunding of prior revenue bonds with proceeds of the Refunding Electric Revenue Bonds, Issue of 2023A and the Electric Revenue Bonds, Issue of 2024A. The Electric System no longer has any variable rate debt.

(9) Fiscal Years 2020-21 through 2022-23 have been restated to remove retainage payable from the calculation of Net Investment in Capital Assets.

(10) Increase in Fiscal Year 2024-25 primarily due to a larger than normal IPA credit accrual at June 30, 2025 as a result of lower than expected fixed fuel costs as participants in IPA burn down their optional coal.

(11) Increase in Fiscal Year 2024-25 due to the increase in need for short-term and long-term energy and resource adequacy agreements.

Electric System Strategic Plan

Strategic Plan. The Riverside Board and City Council have had a formal strategic plan in place with respect to the Electric System since 2001, including the adoption of the following mission statement: “The City of Riverside Public Utilities Department is committed to the highest quality water and electric services at the lowest possible rates to benefit the community.”

Through strategic planning process and workshops, long-term goals and objectives have been established by the Riverside Board to provide the framework to implement the Riverside Public Utilities Department’s Mission Statement. The current Ten-Year Goals adopted by the Riverside Board are (not in priority order):

- Employ state-of-the-art technology to maximize reliability and customer service;
- Foster economic development and job growth in the City of Riverside;
- Communicate effectively the accomplishments, challenges and opportunities for the full utilization of electric and water resources;
- Develop fully low-cost, sustainable, reliable electric and water resources; and
- Enhance the effective and efficient operation of all areas of the utility.

Three-Year Goals and Strategic Plan Objectives are also established to ensure the achievement of these long-term goals, and these are (not in priority order):

- Contribute to the City of Riverside’s economic development while preserving Riverside Public Utilities’ financial strength;
- Maximize the use of technology to improve utility operations;
- Impact positively legislation and regulations at all levels of government;
- Develop and implement electric and water resource plans; and
- Create and implement a workforce development plan.

In 2015, management engaged the community, Riverside Board and City Council through a series of meetings and workshops to create a Utility 2.0 Strategic Plan that provides the vision, changes and actions required to thrive as a Utility of the future. The Utility 2.0 Strategic Plan was designed to facilitate and advance the strategic goals adopted by the City Council in the Riverside 2.0 Strategic Plan as well as the strategic goals of the Riverside Board. Areas of focus for Utility 2.0 include infrastructure improvement, workforce development, utilizing advanced technology and thriving financially, which have been developed through a number of roadmaps. In October 2015, conceptual approval was given by the Riverside Board and City Council to implement the Utility 2.0 Strategic Plan.

The Thriving Financially Roadmap reviewed the areas of rates, reserves, debt and other related policies to ensure the financial balance of Riverside Public Utilities. Rates, cash reserves, debt and other revenue sources were evaluated together with the development of a 10-year pro-forma (financial plan). Several dependent projects were completed during the development of the 10-year pro-forma and rate plan. These projects include the update and approval of the reserve policy, development and approval of an overall fiscal policy, and development and approval of electric and water cost of service studies.

An overall fiscal policy, including a comprehensive section on cash reserves, was completed and adopted by the City Council in July 2016 and subsequently updated and approved by City Council in September 2021, and again in August 2024. On November 17, 2025, an additional update of the fiscal policy was approved by the Board and on December 2, 2025, it was approved by the City Council. The electric and water 10-year pro-forma, cost of service and rate design studies were completed and presented to the City Council in September 2023. The Riverside Public Utilities Department recommended a redesign of its rates over a five-year period to better align with its cost of serving customers and its revenue

requirement. The electric rate restructuring is designed to provide financial stability to support the Electric System's efforts to sustainably improve infrastructure reliability, meet renewable energy and energy efficiency goals, follow legal and regulatory requirements and correct the imbalance of costs versus revenue recovery. Rates have been designed to provide a transition to reflect the nature of underlying costs while encouraging the expansion of customer solar and other distributed generation.

Operating Initiatives and Reserves. Riverside's retail revenues increased by approximately 22.7% from Fiscal Years ended June 30, 2021 to June 30, 2025 primarily as a result of rate plan increases. Historically, retail revenues have generally increased year over year due to annual increases in retail rates. Operating and maintenance expenses (excluding depreciation and public benefit programs) increased by approximately 11.8% from Fiscal Years ended June 30, 2021 to June 30, 2025 due to higher power costs, transmission charges and other miscellaneous operating costs. Positive operating results over time have contributed to improving the City's reserve requirements and the overall goal to continue to be fiscally sound. (See "Unrestricted Cash Reserves.")

Sustainability Initiatives. Riverside has a long history of valuing sustainability and ensuring economic development. Recent efforts for sustainability began in 2001 when Riverside began using light-emitting diodes ("LED") in all City traffic signals to reduce electricity usage. Today, Riverside remains committed to environmental issues and serves as a State leader in sustainability.

Riverside's first sustainability policy statement was adopted in 2007 and ultimately led to the adoption of three Green Action Plans, the latest of which was adopted in 2012. Most recently, the City adopted the Envision Riverside 2025 Strategic Plan in October 2020. This plan incorporates sustainability throughout as a cross cutting value and environmental stewardship as one of six priority areas for Riverside. Additional adopted policies can be found in the City's General Plan 2025 (2007), the Environmentally Preferable Purchasing Policy (2009), the Food and Agriculture Policy Action Plan (2015) and the Riverside Restorative Growthprint (2016). The City is in the process of adopting a new General Plan (GP) and Climate Action and Adaption Plan (CAAP). Once these documents are completed, they will serve in place of the previous Green Action Plans and Riverside Restorative Growthprint.

The City hosts community-wide Green Riverside Leadership Summits. Since 2012, summits have been held every 2 to 3 years. Events in 2012 and 2019 were in partnership with the University of California Riverside. Events in 2014 and 2016 were conducted as part of the community-led Riverside Green Festival and Summit.

Riverside has received numerous recognitions for its sustainability programs and initiatives. In 2009, the California Department of Conservation named Riverside its first "Emerald City" in recognition of its sustainable green initiatives and commitment to help the State achieve multiple state environmental priorities. Riverside was honored in 2016 with the Green Community Award from Audubon International, recognizing the City for its ongoing sustainability initiatives. In addition, Riverside received the 2016 Sustainable Communities Award from the Green California Leadership Summit for its ongoing community-wide sustainability projects and programs that create environmental awareness and action throughout the community, including business, government and private citizens. The Green California Leadership Summit again recognized Riverside in 2018 with its Leadership Award for the City Green Fleet Program. Additionally, in 2022, Riverside was ranked number one in North America for the Green Fleet Award by the NAFA Fleet Management Association.

Riverside initiated an LED streetlight replacement program in 2016. The program will eventually replace all City-owned streetlights by 2026, resulting in approximately 10 million kWh saved annually along with substantially reduced maintenance costs.

Economic Development. The Electric System supports the local economy by offering some of the lowest commercial rates in Southern California combined with attractive economic development electric discount rates to qualified new and expanded load customers. These rate programs have helped create and retain over 3,600 jobs in Riverside since 2010. In late 2021, the Electric System relaunched the commercial energy audit program, which provides key account customers with a comprehensive energy efficiency plan, a priority list of recommended energy efficiency measures, and an estimated return on investment and applicable utility incentives. During Fiscal Year 2024-25, several key customers have utilized this program, which has delivered in excess of 1,443,720 kWh annual savings so far. Additional audits for key account customers are in process, with more anticipated in the future.

Beyond rate incentives, the Electric System also offers local businesses a comprehensive assortment of water and energy efficiency programs to improve building efficiency and reduce customer electric consumption. Fiscal Year 2022-23 saw increased energy efficiencies being realized, with almost 7.3 million kWh saved via the Electric System's commercial programs. Fiscal Year 2023-24 saw savings of 8.1 million kWh, and in Fiscal Year 2024-25, almost 7.8 million kWh of energy savings were achieved.

All of the above-mentioned efforts support organizations and companies to meet their sustainability goals. Most recently, the State's Air Resources Board relocated their Southern California headquarters to Riverside. The campus opened in 2021 and is one of the largest and most advanced vehicle emissions testing and research facilities in the world. Additionally, the headquarters is LEED Platinum, the highest level awarded by the U.S. Green Building Council for the overall sustainability and energy efficiency of a building. This facility, through a combination of on-site solar PV and a 100% renewable energy rate program through the Electric System, receives all of its power from non-carbon emitting resources.

Power Resource Portfolio Management. Riverside manages long-term fuel and power supply risk, renewable resource procurement and compliance with potential state and federal GHG legislation in an integrated fashion. The 2023 Integrated Resource Plan ("IRP") defines the City's risk based, long-term plan for providing stable and predictable rates for customers through the procurement of new energy supply sources at reasonable prices. Riverside updated its IRP in 2023, and the Board and City Council adopted and approved the IRP on April 8, 2024 and June 11, 2024, respectively. The 2023 IRP provides an impact analysis of the City's acquisition of new power resources, specifically towards meeting the State of California's aggressive carbon reduction goals, and the effect these resources will have on Riverside Public Utilities' future projected power supply costs in the 2024-2025 timeframe. Both resource portfolio and energy market issues are examined in the IRP, including (a) projected capacity and resource adequacy needs, (b) renewable portfolio standard ("RPS") mandates, (c) carbon emission goals and mandates, (d) power resource budgetary objectives and cash-flow risk metrics, (e) cost effectiveness of Energy Efficiency and Demand Side Management programs with respect to both the City and customers, (f) impacts of various emerging technologies on carbon reduction goals and future cost of service metrics, and (g) minimizing localized air pollutants and GHG emissions in disadvantaged communities within Riverside.

The IRP provides for a future resource portfolio with a higher reliance on renewable resources, especially geothermal resources, utility-scale solar PV and wind resources, City-owned, lower-carbon emitting natural gas generation, battery energy storage and an increased emphasis on energy efficiency and demand-side management programs. Riverside currently owns 265.5 MW of natural gas-fired generation; this generation allows the City to meet its local capacity requirement imposed by the CAISO while minimizing environmental impacts and cost exposures. This natural gas generation is comprised of the 29.5 MW Clearwater power plant, four 49 MW LM-6000 peaking power plants at RERC, and four 10 MW super-peaking power plants at Springs Generating Project. The IRP studies battery energy storage resources as the potential replacement option for the Springs Generating Project and RERC when these facilities reach end-of-life.

Since late 2012, Riverside has contracted for a diverse portfolio of renewable resources totaling 238.4 MW under medium and long-term power purchase agreements and power sales agreements. This portfolio of renewable resources consists of 96.0 MW of geothermal resources, 45.0 MW of wind resources, and 97.4 MW of solar PV resources. This portfolio of renewable resources enabled Riverside to significantly exceed the RPS mandate of 33% of the retail electricity energy needs by 2020. Riverside served 39% of its retail energy needs with renewable energy in calendar year 2024 (the most recent calendar year for which such information is available). Riverside has also received approximately 761,000 MWh of Historic Carryover RPS credits from the California Energy Commission (the “CEC”); these credits can be used along with the energy from the above-mentioned renewable resources to meet the City’s post-2020 RPS mandates at least through 2028. Additionally, Riverside has contracted for a 125 MW share of the SunZia Wind Power Co., LLC project, which is currently under development and will begin delivering energy in mid-2026, and a current Riverside geothermal contract will begin delivering an additional 20 MW starting in 2027. See the caption “— Renewable Resources.” The additional capacity and renewable energy from these projects will allow Riverside to achieve at least a 60% RPS by 2030 as well as contribute to replacing Riverside’s IPP contract when it expires in June 2027.

Federal Policy on Cyber Security

On February 13, 2013, then-President Obama issued an Executive Order entitled “Improving Critical Infrastructure Security” (the “Executive Order”). Among other things, the Executive Order called for improved information sharing and processing of security clearances for owners and operators of critical infrastructure. The Executive Order further required the Secretary of Commerce to direct the National Institute of Standards and Technology (“NIST”) to lead the development of a framework (the “Framework”) to reduce cyber risks to critical infrastructure. NIST released the first version of the voluntary Framework on February 12, 2014 and finalized the second version of the Framework in April 2018.

The Cybersecurity Information Sharing Act of 2015 was signed into law on December 18, 2015 as part of the year-end Omnibus Appropriations Act. It created an industry-supported, voluntary cyber security information sharing program that encouraged both public and private sector entities to share cyber-related threat information.

The evolution of federal cybersecurity policy since 2015 demonstrates a concerted effort to address the escalating complexity of cyber threats. Early efforts pursued collaboration between the public and private sectors in sharing cyber threat intelligence. Subsequent measures, including Presidential Policy Directive 41 (PPD-41) in 2016, provided a structural framework for coordinating federal agency responses during significant cyber incidents. These initial actions highlighted the importance of defense mechanisms and interagency cooperation in mitigating cyber risks.

In the following years, federal policy evolved to prioritize both proactive and reactive measures. The establishment of the Cybersecurity and Infrastructure Security Agency (CISA) in 2018 institutionalized the protection of critical infrastructure, indicating an essential shift toward recognizing cybersecurity as fundamental to national security. Meanwhile, the Biden administration’s Executive Order 14028 in 2021 marked a key moment, mandating zero trust architectures, enhancing software supply chain security, and standardizing incident detection mechanisms across federal agencies. These initiatives were further reinforced by the Cyber Incident Reporting for Critical Infrastructure Act (CIRCIA) in 2022, which emphasized timely reporting of incidents to facilitate coordinated responses.

More recently, the 2023 National Cybersecurity Strategy reflects an advanced approach to addressing emerging threats such as ransomware and supply chains. Federal policies now aim to anticipate

risks associated with advanced technologies, such as artificial intelligence (AI), while investing in resilient and secure critical infrastructure.

The City participates in sharing and receiving information about cyber threats through several hubs, including the Electricity Information Sharing and Analysis Center and the National Cybersecurity and Communication Integration Center.

In addition, the federal Energy Policy Act of 2005, other provisions of which are discussed under the caption “—Federal Energy Legislation—Energy Policy Act of 2005” below, gave FERC the authority to oversee the reliability of the bulk power system, including the authority to approve mandatory cyber security reliability standards. The North American Electric Reliability Corporation (“NERC”), which FERC has certified as the nation’s Electric Reliability Organization, developed Critical Infrastructure Protection (“CIP”) cyber security reliability standards.

Federal Energy Legislation

Energy Policy Act of 2005. Under the federal Energy Policy Act of 2005 (“EPAAct 2005”), FERC was given refund authority over publicly owned utilities if they sell electrical energy into short-term markets, such as that controlled by the CAISO, and sell eight million MWhs or more of electric energy on an annual basis. In addition, FERC was given authority over the behavior of market participants. Under FERC’s authority, it can impose penalties on any seller for using a manipulative or deceptive device, including market manipulation, in connection with the purchase or sale of energy or of transmission service. The Commodity Futures Trading Commission also has jurisdiction to enforce certain types of market manipulation or deception claims under the Commodity Exchange Act.

EPAAct 2005 authorized FERC to issue permits to construct or modify transmission facilities located in a national interest electric transmission corridor if FERC determines that the statutory conditions are met. EPAAct 2005 also required the creation of an electric reliability organization (an “ERO”) to establish and enforce, under FERC supervision, mandatory reliability standards (the “Reliability Standards”) to increase system reliability and minimize blackouts. Failure to comply with such Reliability Standards exposes a utility to significant fines and penalties by the ERO.

NERC Reliability Standards. As described above, EPAAct 2005 required FERC to certify an ERO to develop mandatory and enforceable Reliability Standards, subject to FERC review and approval. The Reliability Standards apply to users, owners and operators of the Bulk-Power System, as more specifically set forth in each Reliability Standard. On February 3, 2006, FERC issued Order 672, which certified the North American Electric Reliability Corporation (“NERC”) as the ERO. Many Reliability Standards have since been approved by FERC. Such standards pertain not only to the planning, operations and maintenance of Bulk-Power System facilities, but also to the cyber and physical security of certain critical facilities.

The ERO or the entities to which NERC has delegated enforcement authority through an agreement approved by FERC (the “Regional Entities”) may enforce the Reliability Standards, subject to FERC oversight, or FERC may independently enforce them. The Western Electricity Coordinating Council is the Regional Entity for the City’s region. Potential monetary sanctions include fines of up to \$1 million per violation per day. FERC Order 693 further provided the ERO and Regional Entities with the discretion necessary to assess penalties for such violations, while also having discretion to calculate a penalty without collecting the penalty if circumstances warrant.

Federal Regulation of Transmission Access

EPAAct 2005 authorized FERC to compel “open access” to the transmission systems of certain utilities that are not generally regulated by FERC, including municipal utilities if the utility sells more than

four million MWhs of electricity per year. Under open access, a transmission provider must allow all customers to use the system under standardized rates, terms and conditions of service.

FERC Order No. 888 requires the provision of open access transmission services on a nondiscriminatory basis by all “jurisdictional utilities” (which, by definition, does not include municipal entities like the City) by requiring all such utilities to file Open Access Transmission Tariffs (“OATTs”). Order No. 888 also requires “non-jurisdictional utilities” (such as the City) that purchase transmission services from a jurisdictional utility under an open access tariff and that own or control transmission facilities to provide open access service to the jurisdictional utility under terms that are comparable to the service that the non-jurisdictional utility provides to itself. Section 211A of EPCAct 2005 authorizes, but does not require, FERC to order unregulated transmission utilities to provide transmission services. Specifically, FERC may require an unregulated transmitting utility to provide access to its transmission facilities: (1) at rates that are comparable to those that the unregulated transmitting utility charges to itself; and (2) on terms and conditions (not relating to rates) that are comparable to those under which the unregulated transmitting utility provides transmission services to itself which are not unduly discriminatory or preferential.

On February 16, 2007, FERC issued Order 890, which concluded that reform of its pro forma OATT was necessary to reduce the potential for undue discrimination and provide clarity in the obligations of transmission providers and customers. Significantly, in Order 890, FERC stated that it will implement its authority under Section 211A of EPCAct 2005 with respect to unregulated transmitting utilities on a case-by-case basis and retain the current reciprocity provisions.

On July 21, 2011, FERC issued Order 1000, which among other things requires public utility (jurisdictional) transmission providers to participate in a regional transmission planning process that produces a regional transmission plan and that incorporates a regional and inter-regional cost allocation methodology. Further, FERC stated that it has the authority to allocate costs to beneficiaries of transmission services, even in the absence of a contractual relationship between the owner of the transmission facilities and the beneficiary. Under EPCAct 2005, FERC may not require municipal utilities to join regional transmission organizations, in which participating utilities allow an independent entity to oversee operation of the utilities’ transmission facilities. FERC has stated, however, that FERC expects such utilities to participate in the regional processes for transmission planning and that FERC will pursue associated complaints against such utilities on a case-by-case basis.

On May 13, 2024, FERC issued Order 1920 to reform the planning of the nation’s transmission system as well as the allocation of costs for new transmission projects. Order 1920, among other things, requires public utility (jurisdictional) transmission providers to conduct and periodically update long-term regional transmission planning to anticipate future needs, consider a broad set of benefits when planning new facilities, identify opportunities to modify in-kind replacement of existing transmission facilities to increase their transfer capability, propose methods of cost allocation to pay for selected long-term regional transmission facilities, and increase transparency regarding local transmission planning information. Order 1920 expands the role of states throughout the process of planning, selecting and determining how to pay for new transmission facilities.

Order 1920 reflects input FERC sought from interested parties on a variety of reforms aimed at expanding the nation’s transmission grid to accommodate the surge of renewable generation expected in the next two decades to achieve applicable decarbonization goals.

Other Federal Legislation

Legislation is introduced frequently in Congress addressing domestic energy policies and various environmental matters and impacts relating to energy, including the generation of energy using

conventional and unconventional technologies. Issues raised in recent legislative proposals have included implementation of energy efficiency and renewable energy standards, addressing transmission planning, siting and cost allocation to support the construction of renewable energy facilities, cyber security legislation that would allow FERC to issue interim measures to protect critical electric infrastructure, a federal cap-and-trade program to reduce GHG emissions 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 a federal energy efficiency standard and expedited permitting for natural gas drilling projects), cyber security, reducing regulatory burdens, climate change and water quality. Many of these bills, if enacted into law, could have a material impact on the Electric System and the electric utility industry generally. In light of the variety of issues affecting the electric utility sector, federal energy legislation in other areas such as reliability, transmission planning and cost allocation, operation of markets, environmental requirements and cyber security is also possible. The City is unable to predict the outcome or potential impacts of any possible legislation on the City at this time.

Nuclear Regulatory Commission Initiatives

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 or impacting the industry generally may lead the NRC to impose additional requirements and regulations on existing and new facilities. For instance, in the aftermath of the March 2011 earthquake and tsunami that caused significant damage to the Fukushima Daiichi Nuclear Power Plant in Japan, the NRC undertook an independent review of the events at Fukushima Daiichi, including a review of the agency's processes and regulations, in order to determine whether the agency should promulgate additional regulations and possibly make more fundamental changes to the NRC's system of regulation. In addition, various industry organizations developed action plans for American nuclear power plants that are designed to ensure their continued reliability. A task force was formed for PVNGS under the direction of the PVNGS' Chief Nuclear Officer.

The NRC issued regulatory requirements for all 104 operating nuclear reactors located in the United States (including PVNGS) based on the task force's evaluations, which included modifications to operating licenses requiring safety enhancements. A number of improvements have been instituted at PVNGS driven by such requirements and the findings of the task force. Among such improvements are an increase in the redundancy in PVNGS power supply to emergency cooling systems, reinforcement of the spent fuel pool, acceleration of the transfer of spent fuel from the pool to the dry cask storage and added pipelines and associated equipment necessary for supplying additional cooling water to the reactors and the 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.

In the event of noncompliance with its requirements, the NRC has the authority to impose monetary civil penalties or a progressively increased inspection regime that could ultimately result in the shut-down of a unit, or both, depending upon the NRC's assessment of the severity of the situation, until compliance is achieved. The increased costs resulting from penalties, a heightened level of scrutiny and implementation of plans to achieve compliance with NRC requirements may adversely affect the Electric System's financial condition, results of operations and cash flows. See the caption "—Entitlements—PVNGS."

Environmental Issues

General. Electric utilities are subject to continuing environmental regulation. Federal, state and local standards and procedures which regulate the environmental impact of electric utilities are subject to change. These changes may arise from new and changing legislative, regulatory and judicial action regarding such standards and procedures. Consequently, there is no assurance that any Electric System facilities or projects will remain subject to the laws and regulations that are currently in effect, will always

be in compliance with future laws and regulations or will always be able to obtain all required operating permits. In addition, the election of new administrations, including the President of the United States, could substantially impact current environmental standards and regulations and other matters described herein. New laws and regulations could be imposed that could impact the City's ability to operate the Electric System or impose significant compliance costs. The inability to comply with environmental standards could result in, for example, additional capital expenditures, reduced operating levels or the shutdown of individual units which are not in compliance. In addition, increased environmental laws and regulations may create certain barriers to new facility development, may require modification of existing facilities and may result in additional costs for affected resources.

Greenhouse Gas Regulations 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 ("BACT") to control emissions at a facility. 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. 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 regulations under the Clean Air Act that would establish greenhouse gas emission limits, based on pollution control technology or lower-carbon fuels, for new gas plants, existing gas plants, and existing coal plants, as specified. In February 2024, the EPA announced that it will remove the elements that would have applied to existing natural gas-fired power plants from the final version of the rule. Instead, the EPA stated that it will commence a new rulemaking process that will apply to existing natural gas-fired plants and regulate additional pollutants. The rule relating to new gas plants and existing coal plants was finalized on April 25, 2024.

The Trump administration has initiated actions to roll back many of the new carbon pollution standards established under the Biden administration. In June 2025, the EPA proposed to repeal the Biden-era GHG emissions standards for fossil fuel power plants. With various proposals and legal challenges expected, the City is unable to predict at this time the outcomes of any such challenges. Given the uncertainty regarding such matters, it is too early to determine the effect that any final rules promulgated by the EPA regulating GHG emissions from electric generating units will have on the Electric System.

Inflation Reduction Act. On August 16, 2022, President Biden signed the Inflation Reduction Act of 2022 (the "IRA"). The IRA introduces a large amount of funding and grants for governmental and non-profit organizations. Among the most significant energy-related grants are grants for "zero-emissions technologies" and other GHG reduction activities as determined by the EPA. Pursuant to the IRA, public power utilities and other tax-exempt entities will also be given access to refundable direct payment tax credits. Energy-related tax credits that may be available if certain requirements are met include a clean hydrogen production tax credit, a biogas and energy storage credit and enhancements to the credit for carbon capture. The IRA also expands and extends the renewable electricity production tax credit and the investment tax credits for renewable energy sources.

H.R. 1. On July 4, 2025, H.R. 1 (also known as the One Big Beautiful Bill Act) was signed into law, and the bill phases out various renewable energy, energy efficiency, and electric vehicle-related tax credits previously authorized by the Inflation Reduction Act. Pursuant to H.R.1, the production tax credit and investment tax credit are unavailable for any renewable energy project that begins construction after

July 4, 2026 or is placed in service after December 31, 2028. Additionally, H.R. 1 rescinds unobligated IRA funding for various energy and natural resources-related programs.

Air Quality – National Ambient Air Quality Standards. The Clean Air Act requires that the EPA establish National Ambient Air Quality Standards (“NAAQS”) for certain air pollutants, with the goal of improving public health without consideration of cost. When a NAAQS has been established, each state must identify areas within its boundaries that do not meet the EPA standard (known as “non-attainment areas”) and develop regulatory measures in its state implementation plan to reduce or control the emissions of that air pollutant in order to meet the applicable standard and become an “attainment area.”

The EPA periodically reviews the NAAQS for various air pollutants and has in recent years increased, or proposed to increase, the stringency of the NAAQS for certain air pollutants. These developments may result in stringent permitting processes for new sources of emissions and additional state restrictions on existing sources of emissions, such as power plants.

In addition, the U.S. Supreme Court found in its review of *EPA v. EME Homer City Generation, LP* that the EPA has authority to impose a cross-state air pollution rule which curbs air pollution emitted in upwind states to facilitate downwind attainment of three NAAQS.

On November 26, 2014, the EPA proposed to strengthen the stringency of the NAAQS for ozone by lowering the existing ozone standard of 75 parts per billion (“ppb”) to between 65 and 70 ppb, although the EPA also sought public comment on a standard as low as 60 ppb. On October 1, 2015, the EPA issued its final rule, lowering the ozone standard to 70 ppb. Legal challenges to the final rule were filed by a number of states and industry groups. In 2019, the United States Court of Appeals for the District of Columbia Circuit upheld most of the EPA’s 2015 thresholds for ground level-ozone. On July 15, 2020, the EPA announced a proposed decision to retain the existing 70 ppb ozone standard. The decision was finalized on December 7, 2020.

While some particulate matter is emitted directly from sources such as construction sites, unpaved roads, fields, smokestacks or fires, most particles form in the atmosphere as a result of complex reactions of chemicals such as sulfur dioxide and nitrogen oxides, which are pollutants emitted from power plants and other sources. On February 7, 2024, the EPA announced a final rule to strengthen certain NAAQS for fine particulate matter. Areas that are designated as nonattainment areas have planning obligations to demonstrate attainment and meet the new standard within 6 years following the nonattainment designations.

Mercury and Air Toxics Standards. The Clean Air Act provides for a comprehensive program for the control of hazardous air pollutants, including mercury. On February 16, 2012, the EPA finalized a rule, the Mercury and Air Toxics Standards (the “MATS”), establishing new standards to reduce air pollution from coal- and oil-fired power plants under sections 111 (new source performance standards) and 112 (toxics program) of the Clean Air Act. The MATS rule was amended in 2013 and 2014. Under section 111 of the Clean Air Act, the MATS rule revised the standards that new and modified facilities, including coal- and oil-fired power plants, must meet for particulate matter, sulfur dioxide and nitrogen oxide. Under section 112, the MATS set new toxics standards limiting emissions of heavy metals, including mercury, arsenic, chromium and nickel, and acid gases, including hydrochloric acid and hydrofluoric acid, from existing and new power plants larger than 25 MW that burn coal or oil. Power plants were to have up to four years to meet these standards. While many plants already meet some or all of these revised standards, some plants would be required to install new equipment to meet the standards.

The MATS had a minimal impact on the City. IPP, which has coal-fired power plants, did not have to install control technology, and the EPA has deemed the IPP units as low-emitting units. IPP is subject to periodic testing, work practice standards and recordkeeping requirements as a result of the MATS rule. On July 17, 2020, the EPA finalized revisions to the electronic reporting requirements for MATS that

revised and streamlined reporting and provided enhanced access to MATS data, without imposing new monitoring requirements. In April 2024, the EPA finalized a rule that modified regulation of coal- and oil-fired power plants, including further restricting their emissions and changing emissions monitoring requirements.

Effluent Limitations Guidelines and Standards. On June 7, 2013, the EPA proposed to set technology-based effluent limitations guidelines and standards for metals and other pollutants in wastewater discharged from steam electric power plants. The proposal would cover wastewater associated with several types of equipment and processes, including flue gas desulfurization, fly ash, bottom ash, flue gas mercury control and gasification of fuels. The EPA considered best management practices for surface impoundments containing coal combustion residuals. The EPA proposed four preferred alternatives for regulating wastewater discharges. The stringency of controls, types of waste streams covered and the costs varied among the four alternatives. On September 30, 2015, the EPA announced its final Steam Electric Effluent Limitation Guidelines to update the federal limits on toxic metals in discharge wastewater.

In November 2019, the EPA proposed to revise the 2015 effluent limitation guidelines as they relate to existing facilities. The proposed new standards apply to flue gas desulfurization wastewater and bottom ash transport water and are meant to achieve greater pollution reductions than the 2015 standards by taking into account new and more affordable pollution control technologies. The final rule for steam electric power generation point sources was published on August 31, 2020. On August 3, 2021, the EPA announced a planned-rulemaking to strengthen certain discharge limits in the steam electric power generating category. On May 9, 2024, the EPA finalized a supplemental rulemaking for coal-fired plants to strengthen certain wastewater discharge limits.

Climate Change. Legislative and regulatory responses to climate change and the effects of climate change could impact the future operations and costs of the Electric System or individual projects. In addition to the matters discussed above, the City may be impacted by future treaties and federal and state laws, rules and regulations that limit carbon dioxide and other GHG emissions from electric generating facilities. Absent legislative action by the U.S. Congress, the EPA has authority to regulate carbon dioxide and other GHG emissions under the Clean Air Act, and any future administrations could promulgate new rules or rules that repeal, revise and/or replace rules that are currently in effect. Furthermore, changes in temperatures, precipitation and the frequency and severity of extreme weather events (such as tornadoes and flooding) and other impacts of climate change could affect peak demands, the operations of the City's Electric System and the costs of maintaining Electric System facilities and power transmission lines. The impacts of these weather events on current and future operations cannot be predicted at this time.

Electric and Magnetic Fields. A number of studies have been conducted regarding the potential long-term health effects of 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 Electric System.

Resource Adequacy

Resource adequacy requirements apply to the Electric System and are intended to ensure that the Electric System has contracted for sufficient amounts of power resource capacity to meet its customers' needs. To the extent that the Electric System fails to procure sufficient capacity resources to meet its loads, it is subject to payment of CAISO procurement costs of replacement capacity. To the extent that a shortage cannot be attributed to procurement shortfalls, then the costs will be spread as part of market uplift charges. These risks apply in the same manner to all load-serving entities. Because of the increased integration of renewable energy sources, the CAISO is contemplating what could be significant changes to the resource

adequacy framework, with the potential for impacts on market participant costs. It is still too early to assess the potential impacts on the Electric System. The CPUC has ongoing dockets that could also result in changes to resource adequacy and CAISO market requirements. However, the details of such changes remain to be established.

In 2006, the CAISO filed with FERC its Market Redesign and Technology Upgrade (“MRTU”) tariff amendment to implement a comprehensive overhaul of the electricity markets administered by the CAISO. The programs under the MRTU initiative were designed to implement market improvements to assure grid reliability and more efficient and cost-effective use of resources and to create technology upgrades that would strengthen the entire CAISO system. The California energy market under the MRTU includes the following features, among others, which were not part of CAISO’s previous real-time only market tariff:

- An integrated forward market for energy, ancillary services and congestion management that operates on a day-ahead basis;
- Congestion management which represents all network transmission constraints;
- Congestion Revenue Rights to allow market participants to manage their costs of transmission congestion;
- Local energy prices by price nodes (approximately 3,000 nodes in total), also known as locational marginal pricing; and
- New market rules and penalties to prevent gaming and illegal manipulation of the market as well as modifications to certain existing market rules.

The MRTU became operational on April 1, 2009 and the initial MRTU tariff filed with FERC went into effect at that time. Power is scheduled on a nodal basis, rather than the previous zonal system. Furthermore, the MRTU incorporates the CPUC’s resource adequacy requirements to ensure that there are adequate power resources in critical areas. The MRTU requires that scheduling coordinators for all load-serving entities (“LSEs”), which include the City, meet standards concerning forward capacity and power procurement to meet their load requirements.

In September 2005, the Governor signed into law Assembly Bill 380 (“AB 380”), which requires publicly owned utilities to procure adequate capacity and power resources to meet their peak demands and reserves. In October 2005, the CPUC issued a decision requiring that LSEs under its jurisdiction acquire capacity that is sufficient to serve their forecast retail customer load plus a 15-17% reserve margin. The MRTU tariff incorporates the CPUC’s resource adequacy requirements. The MRTU tariff imposes a 15% reserve margin on LSEs that are not CPUC jurisdictional entities, such as the City. Increasing the minimum 15% reserve margin is being considered as part of potential changes to the CAISO’s resource adequacy framework.

The Electric System has historically satisfied its reserve margin requirement through its power supply resources, and the City believes that it will continue to have sufficient power resources to satisfy system capacity requirements as required by the MRTU and AB 380.

Long-Term Resource Adequacy Procurement. Historically, Riverside Public Utilities Department has met most of its annual and monthly resource adequacy requirements by purchasing the capacity attributes from generation resources under long term power purchase agreements (PPAs). This strategy has typically worked for meeting monthly resource adequacy requirements during the winter, since Riverside rarely exhibits a peak load more than 300 MW from November through March. However, Riverside Public

Utilities Department has typically needed to buy additional merchant resource adequacy for non-winter months, with most of this need occurring during July, August, and September. Additionally, this need has grown over time as the utility has contracted for more variable renewable wind and solar resources, because these variable resources don't provide the same amounts of qualifying resource adequacy as either firm baseload resources, dispatchable natural gas generation assets, or dispatchable battery energy storage (BES) assets. Given RPU's need for increasing amounts of resource adequacy, coupled with the recent increasing resource adequacy cost pressures and the anticipated exit from the Intermountain Power Project, it is critically important that the Utility negotiate and secure additional long-term, cost-effective resource adequacy contracts.

On July 2, 2024, the Electric System entered into a 15-year resource adequacy purchase and sale agreement with Vesi 15, LLC for 80 megawatts of battery energy storage capacity located in Visalia California. This project is expected to provide approximately 80 MWh of both Local and Flexible resource adequacy benefits at a levelized price of \$7.94/kw-month for 15 years.

On February 25, 2025, the Electric System entered into a 15-year resource adequacy purchase and financial energy settlement agreement with Baldy Mesa C, LLC located in Adelanto, California. This project is expected to provide approximately 50 MW of both system and flexible resource adequacy benefits at a levelized price of \$8.00/kW-month. Additionally, this agreement has a monthly energy financial settlement priced at \$9.00/kW-month. This financial energy hedge uses each month's four highest and five lowest day ahead index prices to offset the fixed price \$9.00/kW-month hedge payment effectively lowering the overall cost of the resource adequacy component.

State Legislation Affecting the Power Supply

A number of bills affecting the electric utility industry have been introduced or enacted by the State Legislature in recent years. In general, these bills reflect California climate policy developments by regulating greenhouse gas ("GHG") emissions and providing for greater investment in energy efficiency and environmentally friendly generation and storage alternatives, principally through more stringent RPS requirements and more aggressive emissions reduction programs to combat the effects of climate change. Legislation enacted in recent years has also focused on addressing issues relating to wildfire risks. Set forth below is a brief summary of some of these bills and regulatory proceedings.

Senate Bill 350 – Clean Energy and Pollution Reduction Act of 2015. Senate Bill ("SB") 350, enacted in 2015, consists of a multitude of requirements to meet the Clean Energy and Pollution Reduction Act of 2015. The primary components that affect Riverside are: (i) the increase in the mandate of the State's Renewable Portfolio Standard ("RPS") to 50% by December 31, 2030; (ii) the doubling of energy efficiency savings by January 1, 2030; and (iii) providing for the transformation of the CAISO into a regional organization. In addition, there is a specific integrated resource planning mandate embedded in the bill that applies to the 16 publicly-owned utilities ("POUs") that have an annual electrical demand exceeding 700 GWh over a 3-year average, which includes the Electric System.

The bill also requires that an updated RPS Procurement Policy must be approved and adopted before January 1, 2019 and be incorporated into the Electric System's Integrated Resource Plan ("IRP"). An Updated 2018 Renewable Energy Procurement Policy was adopted by the Board and City Council on September 10, 2018 and October 9, 2018, respectively. In parallel, on or before January 1, 2019, the governing board of the Electric System must adopt an IRP and a process for updating the plan at least once every 5 years. The IRP must address specific topics such as energy efficiency and demand response resources, transportation electrification, GHG emissions, energy storage resources, enhanced distribution systems and demand-side management, etc. The IRP must be submitted to the CEC for review, of which the CEC will check if the statutory requirements have been met and will adopt guidelines to govern the

submission of the IRP information. On August 9, 2017, the CEC adopted the POU IRP Submission and Review Guidelines.

On September 30, 2017, the Governor signed SB 338, which requires that the governing board of local POU consider as part of the IRP process the role of existing renewable generation, grid operational efficiencies, energy storage, energy efficiency, and distributed energy resources in meeting the energy and reliability needs of each utility during the hours of peak demand. On August 1, 2018, the CEC adopted a Second Edition of the POU IRP Submission and Review Guidelines to include the requirements of SB 338. On October 3, 2018, the CEC adopted an amendment to the second edition guidelines to include CARB's GHG emission reduction planning targets for IRPs.

On November 26, 2018 and December 11, 2018, the Board of Public Utilities and City Council, respectively, adopted the Electric System's 2018 Integrated Resource Plan. The IRP and additional submittal requirements were submitted to the CEC on December 18, 2018. In April 2019, the CEC issued their Staff Paper Review of the Electric System's IRP, as well as the CEC Executive Director's Determination Letter finding the Electric System to be consistent with the requirements of SB 350. The adoption of this determination occurred at the CEC Business meeting on August 14, 2019.

For the 5-year IRP update cycle mandated by SB 350, on August 5, 2022, the CEC published a Draft Revised Third Edition of the POU IRP Submission and Review Guidelines to reflect the SB 100 RPS procurement target of 60 percent of retail sales by 2030 and extend the IRP forecast horizon from 2030 to 2045. The Electric System completed an updated IRP as per the guidelines, and on April 8, 2024 and June 11, 2024, the Board and City Council, respectively, adopted the Electric System's 2023 IRP. The IRP and additional submittal requirements were submitted to the CEC on June 12, 2024. On July 18, 2025, the Electric System received a letter from the CEC deeming the 2023 IRP to be complete. The Electric System is now awaiting the CEC's review of the 2023 IRP for consistency with the requirements spelled out in SB 350. See the caption "Electric System Strategic Plan – Power Resource Portfolio Management."

The CEC continues to host various workshops on different components of the SB 350 requirement and the Electric System has been monitoring its outcome.

Senate Bill 100 – 100 Percent Clean Energy Act of 2018. On September 10, 2018, the Governor signed into law the 100 Percent Clean Energy Act of 2018 (SB 100). This bill further increased the RPS goals of SBX1-2 and SB 350, while maintaining the 33% RPS target by December 31, 2020, but modified the RPS percentages to be 44% by December 31, 2024, 52% by December 31, 2027, and 60% by December 31, 2030. The current end goal of SB 100 is to have 100% of the state's retail electricity supply generated from a mix of RPS-eligible and zero-carbon resources by December 31, 2045.

The CEC is required to establish appropriate multi-year compliance periods for all subsequent years after 2030 that will require POU to procure not less than 60% of retail sales from renewable resources. In September 2019, the CEC began conducting pre-rulemaking workshops to discuss potential amendments to the RPS Enforcement Procedures for POU that would incorporate the SB 100 mandates. In addition, POU will need to include the increased requirements in their future IRP. On December 1, 2020, the CEC released the third 15-day language for the RPS Enforcement Procedures for POU and adopted it at the December 22, 2020 CEC Business Meeting. It was approved by the Office of Administrative Law (OAL) and made effective July 12, 2021. The updated procedures clarify the interim targets for each year and that compliance periods beginning on and after January 1, 2031 shall be three years in length starting on January 1 and ending on December 31. For each compliance period beginning on or after January 1, 2031, a POU shall demonstrate it has procured electricity products within the compliance period sufficient to meet or exceed an average of 60 percent of the POU's retail sales over the three calendar years of the compliance period.

On December 4, 2020, the CEC issued a draft SB 100 Joint Agency Report, presented by the CEC with CARB and CPUC. The joint agency report is intended to inform policy and planning, which is required to be presented to the legislature every four years starting on January 1, 2021. The final report was published by the CEC and joint agencies on March 15, 2021. On August 22, 2023, the CEC, CARB, and CPUC held a joint workshop to discuss findings and recommendations from the 2021 SB 100 Joint Agency Report and the plan to address these findings and recommendations as the 2025 SB 100 Joint Agency Report is being developed. In 2024, the CEC began hosting workshops to discuss demand scenarios, as well as inputs and assumptions, for use in the 2025 SB 100 Joint Agency Report. Workshops have continued into 2025 and no date has yet been given for when the final report is expected to be adopted. Riverside will continue to monitor the outcome and impacts of any upcoming workshops and regulations in meeting the new requirements.

Senate Bill 1020 – Clean Energy, Jobs, and Affordability Act of 2022. SB 1020, the Clean Energy, Jobs, and Affordability Act of 2022, was signed into law by the State Governor in September 2022 and became effective on January 1, 2023. SB 1020 revises SB 100’s policy on eligible renewable energy resources and zero-carbon resources, and establishes that it is the policy of the State that eligible renewable energy resources and zero-carbon resources supply: (i) 90% of all retail sales of electricity to California end-use customers by December 31, 2035; (ii) 95% of all retail sales of electricity to California end-use customers by December 31, 2040; (iii) 100% of all retail sales of electricity to California end-use customers by December 31, 2045; and (iv) 100% of electricity procured to serve all state agencies by December 31, 2035.

Assembly Bill 1279 – California Climate Crisis Act. In September 2022, the State Governor signed into law Assembly Bill (“AB”) 1279, which became effective on January 1, 2023 and established additional GHG emission reduction goals. AB 1279 declares the policy of the State both to achieve net-zero GHG emissions as soon as possible, but no later than 2045, and to achieve and maintain net negative GHG emissions thereafter, and to ensure that by 2045, Statewide anthropogenic GHG emissions are reduced to at least 85% below the 1990 levels. Under AB 1279, “net zero GHG emissions” means emissions of GHGs to the atmosphere are balanced by removals of GHG emissions over a period of time. AB 1279 directed the California Air Resources Board (“CARB”) to ensure that its scoping plan identifies and recommends measures to achieve these policy goals. The State Legislative Analyst’s Office is required to conduct an independent assessment of progress towards the bill’s objectives every two years and to make its findings available to the public.

Assembly Bill 32 – Global Warming Solutions Act of 2006. AB 32, enacted in 2006, requires that utilities in California reduce their GHG emissions to 1990 levels by the year 2020. On September 8, 2016, the Governor of California expanded on this bill by approving SB 32, which requires the state board to ensure that statewide greenhouse gas emissions are reduced to 40% below the 1990 level by 2030.

AB 32 tasked CARB to develop regulations for GHG, which became effective January 1, 2012. Emission compliance obligations under the cap-and-trade regulation began on January 1, 2013. The Cap-and-Trade Program was implemented in phases with the first phase starting from January 1, 2013 to December 31, 2014. This phase placed an emission cap on electricity generators, importers and large industrial sources emitting more than 25,000 metric tons of carbon dioxide-equivalent greenhouse gases per year. In 2015, the program expanded to cover emissions from transportation fuels, natural gas, propane, and other fossil fuels. Since the enactment of AB 32, the Electric System has actively participated with major investor-owned utilities and POUs to affect the final rules and regulations with respect to AB 32 implementation.

The Cap-and-Trade Program requires electric utilities to have GHG allowances on an annual basis to offset GHG emissions associated with generating electricity. CARB will provide a free allocation of GHG allowances to each electric utility to mitigate retail rate impacts. If a utility requires additional

allowances, then they must be purchased through the auction or on the secondary market to offset its associated GHG emissions. Each allowance can be used for compliance purposes in the current year or carried over for use for future year compliance. The Electric System's free allocation of GHG allowances is expected to be sufficient to meet the Electric System's direct GHG compliance obligations.

Any allowance not used for current year compliance or carried over for future use in compliance must be sold into the quarterly allowance auctions administered by CARB. Proceeds from the auctions must be used for the intended purposes specified in AB 32, which include but are not limited to procurement of renewable resources, energy efficiency and conservation programs and measures that provide clear GHG reduction benefits. The Electric System is segregating the proceeds from the sales of allowances in the auctions as a restricted asset.

Similar to the Cap-and-Trade Program, the Low Carbon Fuel Standard ("LCFS") program is a key component of the market mechanisms authorized by AB 32 to achieve the State's GHG emissions reduction goals. LCFS seeks to reduce the carbon intensity ("CI") of fuels used for transportation by establishing an annual CI target. Fuels that have a CI greater than the target have a compliance obligation and are required to turn in LCFS credits, while fuels with a CI lower than the target may generate credits.

In 2009, the LCFS rulemaking began and consisted of two rulemaking packages (Part 1 and Part 2) that were approved by CARB on January 12, 2010 and April 15, 2010, respectively, with implementation effective January 1, 2011. The program then underwent litigation in the State and the regulation was re-adopted with modifications on November 16, 2015, effective January 1, 2016. Under the LCFS program, electricity is considered a fuel subject to the regulation when it is used as a transportation fuel in electric vehicles. However, because the CI of electricity is substantially lower than the annual CI targets under the program, electricity is categorized as a fuel that generates LCFS credits and participation in the program is voluntary.

In March 2018, the City opted into the LCFS program and began generating LCFS credits for the first quarter of 2018. These credits are associated with two sources – unmetered electricity used to charge residents' electric vehicles at their homes (residential base credits) and from electric forklifts charging at private businesses (forklift credits). CARB calculates the credits that the Electric System will receive and the Electric System submits quarterly reports to receive the credits. The Electric System has established a restricted regulatory requirement reserve to comply with regulatory restrictions and governing requirements related to the use of the LCFS proceeds. The available funds are to be utilized for qualifying programs that support the Electric System's customers who are existing and future electric vehicle owners.

Simultaneously in 2018, the LCFS regulation was amended and adopted on January 4, 2019. The amendments required electric utilities that have opted into the LCFS program to participate in and manage a statewide point-of-sale rebate program for new electric vehicles. This program is called the California Clean Fuel Reward Program ("CFR") and the City joined the program in May 2020. To fund the program, electric utilities are required to contribute proceeds received from the sales of residential base credits beginning with the credits the Electric System received in the fourth quarter of 2019 (generated from electricity used for transportation in the second quarter of 2019). Residential base credits the Electric System received prior to that time are not subject to the contribution requirements. Additionally, a "startup" contribution from proceeds was required to be submitted by January 31, 2021. After the initial deposit of funds in November 2020, deposits to the CFR program are required by March 31 annually.

In November 2024, CARB adopted amendments to the LCFS regulation that went into effect on July 1, 2025. Under the new amendments, the CFR program will now provide point-of-purchase rebates for new and/or used commercial medium or heavy-duty EVs rather than new light-duty EVs. Additionally, the Electric System has been reclassified as a small publicly owned utility and will no longer have an obligation to contribute funds to the CFR program, although its customers are still eligible to participate in

the program. The approved amendments also included changes to the list of preapproved projects for holdback credits and no longer provides credits for electric forklift charging to electric utilities.

CARB is currently in the midst of a new rulemaking process, which would make minor amendments to the LCFS regulation. The proposed amendments would not affect the Electric System's current LCFS activities.

Assembly Bill 398 – GHG Cap-and-Trade Program Extension. AB 398 was signed on July 25, 2017 and approved extending the GHG cap-and-trade program to December 31, 2030, which was originally implemented under AB 32. This bill was also a companion bill to AB 617 as part of a legislative package that will be discussed further below. In addition, AB 398 required CARB to update their scoping plan no later than January 1, 2018. AB 398 also requires all adopted GHG rules and regulations to be consistent with this plan. On July 27, 2017, CARB approved the 2016 Cap-and-Trade Amendments, which includes the Electric System's 2021-2030 allowance allocations it will receive each year. The Electric System's allowance allocations should be sufficient to cover all of its 2021-2030 direct compliance obligations.

Initially, it was unclear under AB 398 whether the Electric System would be required to consign 100% of its allowances to the market and then purchase allowances to fulfill its compliance obligations. Since the start of the Cap-and-Trade program in 2012, POU's have been able to directly assign allowances for compliance. However, in 2017, CARB announced they were reconsidering this provision. In early 2018, after much discussion and collaboration with CARB in which the POU's demonstrated that they continue to include the price of GHG emissions in the cost of energy, it was agreed that the POU's would not be forced to consign their allocated direct-compliance allowances to auction. Other unknown components of the law include the banking provisions and the specific GHG revenue spending requirement for revenues generated from the sale of excess allowances.

In June 2021, CARB began focus area discussion workshops as part of the next iteration of the Scoping Plan Update on four areas: 1) electricity sector, 2) transportation sector, 3) equity and environmental justice, and 4) natural and working lands. On June 8, 2021, CARB hosted a workshop series to commence development of the 2022 Scoping Plan Update to Achieve Carbon Neutrality by 2045. Starting in July 2021 and onward, a series of technical workshops were hosted to cover various topics and sectors within the Scoping Plan. On December 15, 2022, CARB Board unanimously adopted the 2022 Scoping Plan Update. The Scoping Plan focuses on laying out the path to achieving carbon neutrality and reducing anthropogenic GHG emissions by 85 percent below 1990 levels no later than 2045. The 2022 Scoping Plan includes decarbonization through the electrification of transportation and buildings, which will increase the transportation and generation needs of the Electric System. The Scoping Plan also states that storage and demand-side management will be essential to maintaining reliability as more renewables are incorporated into the electric grid.

On July 27, 2023, CARB held a workshop on the potential amendments to the cap-and-trade regulation. The CARB is again proposing the requirement for consignment of POU allocations, which would add significant cost uncertainty into energy pricing and require the Electric System to purchase allowances from auction using alternative ratepayer funds. Potential impacts also include a decrease of annual allowance allocations and impacts to the mandatory reporting requirement. The CARB has shown a particular interest in ensuring that allowance value targets low-income and priority communities. The CARB has continued to hold public workshops to solicit feedback on potential amendments, though no formal rulemaking has yet begun. The Electric System will continue to monitor the outcome and impacts of the upcoming regulations on its service territory and ratepayers.

Assembly Bill 1207 – GHG Cap-and-Trade Program Reauthorization. AB 1207 was signed on September 19, 2025 and extends California's cap-and-trade program to 2045 and renames it "Cap-and-Invest." On October 29, 2025, CARB conducted a workshop regarding potential amendments to the Cap-

and-Invest program. During the workshop, CARB addressed potential program updates to align with recent legislation and climate targets. CARB also acknowledged that they need to remove approximately 118 million allowances in total from the 2027-2030 annual budgets but did not describe the specific reductions expected per sector. CARB is aiming to bring proposed amendments to CARB in April 2026 for adoption. The Electric System will be monitoring the proposed amendments and development of the regulations.

Assembly Bill 617 – Air Quality Monitoring. AB 617 was signed on July 26, 2017 and was part of a legislative bill package with AB 398, which authorized the extension of the cap-and-trade program in the State. AB 617 addresses the disproportionate impacts of air pollution in areas impacted by a combination of economic, health, and environmental burdens. These burdens include combinations of poverty, high unemployment, health conditions such as asthma and heart disease, air and water pollution, and hazardous wastes. Both CARB and local air districts are required to take specific actions to reduce air pollution and toxic air contaminants from commercial and industrial sources, including from electricity-generating facilities. The bill required CARB, by October 1, 2018, to prepare a statewide monitoring plan regarding technologies and reasons for monitoring air quality and, based on that plan, identify the highest priority locations for the deployment of community level air monitoring systems. Local air districts are required to deploy the air monitoring systems in the specified communities by July 1, 2019. Additional locations for the deployment of the systems will be identified annually by CARB beginning January 1, 2020. The CARB is also required to provide grants to community-based organizations for technical assistance and to support community participation in the programs. In turn, this effort would require the local air district of the selected community to adopt a community emissions reduction program.

Additionally, AB 617 requires CARB to develop uniform reporting standards for air pollutants and toxic air contaminants for specific uses, including electricity-generating facilities. Air districts are to adopt an expedited schedule for implementing best available retrofit control technologies for the uses, while CARB will identify these technologies.

This bill affects the City and the Electric System by imposing additional reporting requirements, particularly on power plants, and potentially adding or improving air monitoring systems in selected communities located within the City of Riverside. For Riverside, the local air district is the Southern California Air Quality Management District (“SCAQMD”). The CARB and SCAQMD have held and continue to hold community meetings to implement the required elements of AB 617. Preliminary discussions and proposals have already been conveyed by community members from the City as well as from the University of California, Riverside proposing areas for community air monitoring and planning. The City and Electric System are monitoring the progress of the community meetings and the two proposed areas for any impacts.

Senate Bill 1368 – Emission Performance Standard. The state legislature passed SB 1368 in 2006, which mandates that electric utilities are prohibited from making long-term financial commitments (commitments greater than five years in duration) for generating resources with capacity factors greater than 60% that exceed a GHG emission factor of 1,100 pounds/MWh. SB 1368 essentially prohibits any long-term investments in generating resources based on coal. Thus, SB 1368 initially disproportionately impacted Southern California POU, as these utilities had heavily invested in coal technology. However, additional legislation such as SBX1-2, SB 350, SB 100, and SB 32 have now led to a gradual decrease in the generation of existing coal resources to serve load.

Riverside has ownership entitlement rights to 136 MW of IPP. IPP has a GHG emission factor of approximately 2,000 pounds/MWh. Therefore, under SB 1368, Riverside is precluded from renewing its IPP Power Purchase Contract at the end of its term in June 2027.

Going forward, SB 1368-related issues are expected to have minimal impact to the CAISO markets as the percentage of load served by coal resources is small. However, to the extent that significant numbers

of coal plants throughout the western United States start to retire in the next 5 to 15 years, it is possible that there could be a tightening of supply throughout the western United States electricity market. In turn, this could lead to higher regional costs and potentially reduced system reliability.

Senate Bill 1037 – Energy Procurement and Efficiency Reporting. SB 1037 was signed into law by the State Governor in September 2005. The law requires publicly owned electric utilities, when procuring energy for long-term needs, to first acquire all available energy efficiency, demand reduction and renewable resources that are cost effective, reliable and feasible. SB 1037 also requires Riverside to report annually to its customers and to the State its investment in energy efficiency and demand reduction programs. Riverside is complying with these reporting requirements.

Assembly Bill 2514 – Energy Storage. AB 2514 “Energy Storage Systems” was signed into law on September 29, 2010. In 2012, AB 2227 amended the reporting timeline of the energy storage targets referenced in AB 2514. The law directs the governing boards of POU’s to consider setting targets for energy storage procurement, but emphasizes that any such targets must be consistent with technological viability and cost effectiveness. The law’s main directives for POU’s and their respective deadlines are as follows: (a) to open a proceeding by March 1, 2012 to determine appropriate targets, if any, for the utility to procure viable and cost-effective energy storage systems, and (b) to adopt an energy storage system procurement target by October 1, 2014, if determined to be appropriate, to be achieved by the utility by December 31, 2016, and a 2nd target to be achieved by December 31, 2020. POU’s were required to submit compliance reports to the CEC of their first adopted target by January 1, 2017.

Energy storage (“ES”) has been advocated as an effective means for addressing the growing operational problems of integrating intermittent renewable resources, as well as contributing to other applications on and off the grid. In general, ES is a set of technologies capable of storing previously generated electric energy and releasing that energy at a later time. Currently, the commercially available ES technologies (or soon to be available technologies) consist of pumped hydroelectric generation, compressed air systems, batteries and thermal ES systems.

On February 17, 2012, as per the statute, the City of Riverside’s Board of Public Utilities opened a proceeding to investigate the various energy storage technologies available and determine if the City should adopt a 2016 energy storage procurement target. The City finished its investigation of energy storage pricing and benefits in September 2014 and adopted a zero-megawatt target based on the conclusion that the viable applications of energy storage technologies and solutions at the time were not cost effective and outweighed the benefits that it might provide to our electrical system. The City had to reevaluate its assessment by October 1, 2017 and report to the CEC any modifications to its initial target resulting from this reevaluation.

On March 3, 2015, City Council approved the Ice Bear Pilot program for 5 MW. The program is intended to reduce load during peak hours by shifting load to off-peak hours, improve energy efficiency, and demonstrate the City’s proactive support of the State’s energy storage goals. Additionally, on July 28, 2015, the City Council approved a 20-year power purchase agreement for the City to procure renewable energy from the Antelope DSR Solar 1 Photovoltaic Project that includes a built-in energy storage option for the buyers to exercise during the first fifteen years of operation.

On December 12, 2016, Riverside submitted its first compliance report to the CEC describing Riverside’s proactive efforts in investigating viable energy storage options in the market and conducting energy storage pilot projects within the City to fulfill its first adopted target.

On September 11, 2017 and September 26, 2017, after reevaluating its assessment of the first adopted energy storage procurement target of zero megawatts, the Riverside Board and City Council,

respectively, approved and adopted the second energy storage procurement target of six megawatts for submittal to the CEC.

Senate Bill 380 – Moratorium on Natural Gas Storage – Aliso Canyon. On October 23, 2015, a significant gas leak was discovered at the Aliso Canyon natural gas storage facility, which makes up 63% of total storage capacity of Southern California Gas Company (“SoCalGas”) and serves 17 gas-fired power generation units. On May 10, 2016, the State Governor signed SB 380, placing a moratorium on Aliso Canyon’s natural gas storage usage until rigorous tests were performed and completed by the Division of Oil, Gas, and Geothermal Resources (“DOGGR”) as to which wells could continue to be in operation. This moratorium caused great concern regarding the reliability of natural gas supplies in the upcoming summer and winter months. An action plan study area was initiated to review the summer and winter assessment that was conducted as a joint effort between the CPUC, CEC, CAISO and Los Angeles Department of Water and Power. Although the area of study neither includes nor immediately impacts Riverside, it is highly plausible that the Electric System could still experience curtailed gas deliveries under certain adverse low-flow gas scenarios.

Beginning June 1, 2016, SoCalGas implemented new Operational Flow Order (“OFO”) tariffs due to limitations surrounding Aliso Canyon storage injections and withdrawals. These tariff changes were put in place to reduce the probability of natural gas curtailments, which would disproportionately impact Riverside due to the requirements to operate internal natural gas generation to maintain system reliability during the summer. Also, gas curtailments during high peak days could lead to severe service curtailments throughout Riverside. Therefore, the Electric System immediately increased internal communication across divisions, created internal gas curtailment procedures to address this specific issue, and created revised dispatch procedures when load forecasts exceed 400 MW. These tighter OFO tariff restrictions were scheduled to conclude upon the return of Aliso Canyon to at least 450 million cubic feet per day (“MMcfd”) of injection capacity and 1,395 MMcfd of withdrawal capacity. Aliso Canyon had not been able to meet its injection and withdrawal targets, therefore, these tighter OFO tariff restrictions continued to remain in effect. In addition, the Electric System continues to communicate daily with the CAISO and SoCalGas on any changes that could impact our service territory.

On February 9, 2017, pursuant to SB 380, the CPUC opened a three-phase investigation to determine the feasibility of minimizing or eliminating the use of Aliso Canyon. On July 19, 2017, DOGGR issued a press release on their determination, in concurrence with the CPUC, that Aliso Canyon was safe to resume injections up to 28% of the facility’s maximum capacity. On that same day, the CEC issued a different press release with a recommendation urging closure of Aliso Canyon in the long-term. On July 31, 2017, SoCalGas resumed injections. Effective July 23, 2019, the CPUC approved the Aliso Canyon Withdrawal Protocol, a protocol describing the process to follow before making a withdrawal from the natural gas storage facility. The protocol was developed with input from the CEC, the CAISO, and LADWP, and enables SoCalGas to withdraw from the Aliso Canyon natural gas storage facility when specific conditions are met related to Low OFO calculations, Southern California natural gas inventory levels, and/or emergency conditions.

Senate Bill 380 added Section 715 to the Public Utilities Code, which requires the CPUC to determine the range of Aliso Canyon inventory necessary to ensure safety, reliability, and just and reasonable rates. In the Section 715 Report, the Energy Division of the CPUC recommended that the maximum allowable Aliso Canyon inventory increase from 24.6 to 34 billion cubic feet (“Bcf”) for summer 2018 and going forward, due to continuing pipeline outages on the SoCalGas system. As of October 7, 2020, the final results of the 114 injection well tests are as follows: 66 wells have completed all required tests and have received final DOGGR (now the California Geologic Energy Management Division (“CalGEM”)) approval; 27 wells have been taken out of operation; and 21 wells have been plugged and abandoned. The CalGEM reduced the Aliso Canyon safe inventory limit from 86 Bcf to 68.6 Bcf.

On November 4, 2021, the CPUC voted to allow SoCalGas to increase the amount of natural gas inventory at the Aliso Canyon Natural Gas Storage Facility from 34 Bcf to 41.16 Bcf, to ensure SoCalGas meets minimum reliability needs.

On September 23, 2022, the CPUC issued a Ruling that finds based on the investigation analysis, that the Aliso Canyon Natural Gas Storage Facility is needed to maintain the reliability of the natural-gas system and to help stabilize gas and electric rates until other resources are available to serve the Los Angeles Basin. In the same Ruling, the CPUC sought comments on a Staff Proposal presenting a framework to eliminate the need for Aliso Canyon by increasing non-gas-fired electricity generation and storage, building electrification, and energy efficiency. The proposal quantifies the current need for Aliso Canyon and estimates an annual increase of 1,084 MW of non-gas-fired electric generation capacity to reliably serve all energy demand without the use of Aliso Canyon by 2027. Because natural gas and electricity systems and demands are constantly evolving, this proposal suggests a biennial assessment where staff from the CPUC and CEC update supply and demand information and consider whether gas demand reductions are on track with proposed targets. If not, staff will consider whether those targets should be adjusted. If gas demand is declining on pace to meet or exceed targets, staff would recommend whether the maximum storage inventory at Aliso should be reduced. This process would continue every other year until Aliso Canyon is phased out.

In winter 2022-23, California and the Western U.S. experienced historically high natural gas prices due to widespread, below-normal temperatures; high natural gas consumption; pipeline constraints; reduced natural gas flows; and low storage inventories. On August 31, 2023, the CPUC approved an increase to the maximum storage level allowed at Aliso Canyon from 41.16 Bcf up to the safety limit set by CalGEM of 68.6 Bcf. The decision allows more natural gas to be injected and stored at Aliso Canyon to help secure energy reliability and protect against high natural gas and electric prices. The decision will not impact progress in proceeding towards phasing out the need for Aliso Canyon.

In December 2024, CPUC issued a proposed decision establishing an ongoing biennial review process, starting June 2025, to assess Aliso Canyon's necessity and recommend adjustments to its maximum storage level in 10 Bcf increments based on evolving demand and reliability forecasts. A natural gas peak demand target of 4,121 MMcf/d was defined as the threshold at which Aliso Canyon could be considered for closure; if forecasts two years ahead meet this threshold and the assessment supports closure without risking reliability or consumer rates, CPUC will initiate a proceeding toward decommissioning. In late December 2024, CPUC voted 4-0 to keep Aliso Canyon open indefinitely, signaling that while a roadmap exists for eventual closure, the facility remains needed to ensure near-term energy reliability.

Assembly Bill 802 – Building Energy Use Benchmarking and Public Disclosure Program. On October 8, 2015, AB 802 was signed into law creating a new statewide building energy use benchmarking and public disclosure program for the State of California. The bill requires California utilities to maintain records of energy usage data for all buildings (i.e., commercial and multifamily buildings over 50,000 square feet gross floor area) for at least the most recent 12 months. Beginning January 1, 2017, utilities are required to deliver or provide aggregated energy usage data for a covered building, as defined, to the owner, owner's agent or operator upon written request. The Electric System provides consumption data for buildings meeting the legislative requirement upon owners' written request. The CEC adopted regulations on October 11, 2017 and approved the regulation action to be effective on March 1, 2018. Building owners are required to report this information annually beginning on June 1, 2018.

Assembly Bill 1110 and Senate Bill 1158 – Legislation Relating to Greenhouse Gas Emissions Reporting for Power Resource Disclosure. On September 26, 2016, AB 1110 was signed into law requiring GHG emissions intensity data and unbundled renewable energy credits to be included as part of the retail suppliers' power source disclosure ("PSD") report and power content label ("PCL") to their customers. GHG emissions intensity factors will need to be provided for all retail electricity products. The

inclusion of this new information requirement on the PCL will begin in 2021 for calendar year 2020 data. In addition to still being required to post the PCL on the city website, the bill also reinstated the requirement that the PCL disclosures must be mailed to the customers starting in 2017 for calendar year 2016 data unless customers have opted for electronic notifications. In accordance with this requirement, Riverside reinstated the inclusion of printed disclosures of the PCL with its September 2017 bills to the customers.

In 2017, the CEC began hosting workshops on the GHG emissions disclosure requirements and initiated the rulemaking process of updating their PSD regulations. A pre-rulemaking phase also began that included an implementation proposal on AB 1110. The legislation requires the CEC to adopt guidelines by January 1, 2018. In early 2018, the CEC provided an update to their 2017 pre-rulemaking activities and proposed changes to the regulations and reports, but additional workshops were needed. In March 2019, the last pre-rulemaking workshop was held by the CEC, with the intent to begin the formal rulemaking in May, but was delayed until September 2019. On December 11, 2019, the CEC adopted the updated PSD regulations, which changed the timing of the inclusion of the GHG emissions intensity data to be included in the PCL starting in 2021 for calendar year 2020 data. The adoption of the updated PSD regulations and how the additional GHG emissions intensity information would be conveyed to customers in the PSD report and PCL was approved on May 4, 2020. The most notable changes to the report and label are the addition of the GHG emissions intensity and how certain energy resources would be conveyed to the customers to meet the AB 1110 requirement.

On September 16, 2022, SB 1158 was signed into law which requires, beginning January 1, 2028, every retail supplier to annually report to the CEC information concerning electricity supply used to serve load, including the retail supplier's hourly sources of electricity and the emissions of GHG associated with those sources of electricity. The bill also requires the CEC to share and publish the information annually on its website in an aggregated summary. The CEC is required to adopt rules to implement these reporting requirements on or before July 1, 2024. The CEC initiated the formal rulemaking period on May 17, 2024 by releasing an initial 45-day language package and hosted a rulemaking workshop on June 11, 2024 to solicit feedback on the proposed changes. A second 45-day language package was released October 1, 2024, and a 15-day language package was released December 6, 2024. The CEC adopted the regulation on February 12, 2025. Riverside continues to monitor upcoming workshops and draft regulations for any impacts to the utility's reporting and portfolio of resources.

Senate Bill 859 – “Budget Trailer Bill” – Biomass Mandate. In the final two days of the 2015-2016 legislative session, a “budget trailer bill” on how to spend cap-and-trade funds was amended to include a biomass procurement mandate for local publicly-owned utilities serving more than 100,000 customers. These utilities would be required to procure their pro-rata share of the statewide obligation of 125 MW based on the ratio of the utility's peak demand to the total statewide peak demand from existing in-state bioenergy projects for at least a five-year term. On September 14, 2016, the Governor of California signed SB 859 into law.

On October 13, 2016, the CPUC adopted Resolution E-4805, which established that the POUs be allocated 29 MW of the 125 MW statewide mandate. The City determined that their obligated share would be 1.3 MW to meet the mandate. It is expected that the City's proportion of these facilities will be counted towards the Electric System's Renewable Portfolio Standard (“RPS”) goals.

In 2017, the affected POUs consisting of the cities of Anaheim, Los Angeles, and Riverside, Imperial Irrigation District, Modesto Irrigation District, Sacramento Municipal Utility District, and Turlock Irrigation District decided it would be beneficial to procure a contract together for economies of scale. This was accomplished by utilizing the Authority to issue a Request for Proposal on behalf of all the affected POUs, since four of the seven POUs affected are existing Authority members.

In January 2018, the Riverside Board and City Council approved the City's five-year Power Sales Agreement with the Authority for 0.8 MW from the ARP-Loyalton biomass project. On April 20, 2018, the facility declared commercial operation.

On September 21, 2018, the Governor signed into law SB 901, which primarily focuses on strengthening California's ability to prevent and recover from catastrophic wildfires such as via forest management activities, updating requirements for maintenance and operations of utility infrastructure, assessing GHG emissions impact, and protecting ratepayers. The bill also included a clause for certain biomass contracts that were procured or operating in 2018 and set to expire on or before December 31, 2023 to be offered a contract extension. The Electric System is required to "seek to amend the contract to include, or seek approval for a new contract that includes, an expiration date 5 years later than the expiration in the contract". Although there is no enforcement mechanism, the ARP-Loyalton biomass project meets the above criteria and feedstock requirement referenced in SB 901 and SB 859. The Electric System had been working with ARP-Loyalton to comply with SB 901, but production generation from the project site ceased in early January 2020. In late February 2020, ARP-Loyalton filed for Chapter 11 bankruptcy. Sale of the project was approved by the court to a new owner on April 30, 2020. The term of the Agreement ended on April 19, 2023, fulfilling the regulatory requirements, and on April 30, 2024, the courts approved the bankruptcy filing and associated settlement, which reimbursed the contractors for all the legal fees associated with the bankruptcy.

On February 24, 2020 and March 17, 2020, Riverside's Board and City Council, respectively, adopted a five-year Purchase Agreement with Roseburg Forest Products Co. for 0.5 MW in capacity to fulfill the remaining MW share of the mandate. On February 16, 2021, Roseburg declared commercial operation.

Senate Bill 1109 – Extension of Biomass Mandate. SB 1109, signed into law by the State Governor on September 16, 2022 (and effective on January 1, 2023), modifies SB 859, requiring publicly owned utilities that serve more than 100,000 customers to procure, by December 1, 2023, through financial commitments of 5 to 15 years, their proportionate shares (based on the ratio of the utility's peak demand to the total Statewide peak demand), of 125 MW of cumulative rated capacity from existing bioenergy projects that generate energy from: (a) a byproduct of sustainable forestry management; and (b) high fire-hazard zones. However, such modified requirements under SB 1109 do not apply if the utility, either directly or through a joint powers authority, entered into the five-year financial commitments as previously required pursuant to SB 859 and those commitments included: (1) a contract with a facility operator that was, on June 1, 2022, in bankruptcy; or (2) a contract for a project that does not deliver energy to the utility. SB 1109 will not impose additional requirements on Riverside because the City entered into the five-year financial commitments as previously required pursuant to SB 859. SB 1109 also modified SB 901's contract extension requirement, instead requiring utilities with certain biomass contracts that expire before December 31, 2028, to seek to extend their term five years past the expiration date operative in 2022. These contract extension requirements, similarly, do not apply to Riverside under SB 1109.

Senate Bill 1028, Senate Bill 901, and Assembly Bill 1054 – Legislation Relating to Wildfires. SB 1028, which was signed into law by the State Governor in September 2016, requires municipal electric utilities to construct, maintain and operate their electrical lines and equipment in a manner that will minimize the risk of catastrophic wildfire posed by those electrical lines and equipment. SB 1028 also requires the governing board of each municipal electric utility to make an initial determination as to whether its overhead electric lines and equipment pose a significant risk of catastrophic wildfire based on historical fires and local conditions and if so, to present for board approval wildfire mitigation measures that the utility intends to undertake to minimize the risk. While governing boards must make this determination independently based on all relevant information, the CPUC's Fire Threat Map is an important factor in this process. The Fire Threat Map was adopted by the CPUC on January 19, 2018. According to the Fire Threat Map, parts of the Electric System are in an elevated fire threat zone. The Electric System owns transmission

assets, including, but not limited to, wires, poles and other needed equipment to safely maintain and deliver power generated from generation assets located outside City limits.

SB 901, which was signed into law by the State Governor in 2018, addresses the response to, mitigation of and prevention of wildfires. SB 901 requires municipal electric utilities to prepare before January 1, 2020 and annually thereafter a wildfire mitigation plan (a “WMP”), which is to be submitted to a newly created Wildfire Safety Advisory Board (the “WSAB”). SB 901 further requires utilities to present their WMPs in an appropriately noticed public meeting, to accept comments on the plan from the public, other local and state agencies and interested parties and to verify that the plan complies with all applicable rules, regulations, and standards, as appropriate. SB 901 also requires the utilities to contract with a qualified independent evaluator to review and assess the comprehensiveness of their WMPs. The report of the independent evaluator is to be made available on the Internet and to be presented at a public meeting of the utilities’ governing boards.

Under AB 1054, which was signed into law in July 2019, the WSAB is required to provide comments and an advisory opinion to each publicly owned utility regarding the content and sufficiency of its plan and to make recommendations on the mitigation of wildfire risks. AB 1054 requires each publicly owned utility to comprehensively revise its WMP at least once every three years.

The City fully complied with AB 1054 and the City Council formally adopted the Wildfire Mitigation Plan on December 17, 2019. Following City Council adoption, this approved plan was also submitted to the WSAB on May 6, 2020, as required.

On December 9, 2020, the WSAB completed their review of all publicly owned utilities’ initial WMPs and issued an advisory opinion applicable to all POUs. It identified several themes that all POUs were requested to address and were not required to incorporate the recommendations as part of the next annual WMP update. Instead, POUs were asked to respond to a matrix of questions to be submitted at the same time as the next update of the WMP. The matrix is not required to be presented to the public utilities’ governing boards.

On June 14, 2021, the Electric System presented the updated 2021 WMP to its Board and received a recommendation that the City Council approve the 2021 Riverside Public Utilities WMP annual update for submittal to the WSAB by July 1, 2021. During the Board meeting, staff identified updates to the WMP that would allow the Electric System to better respond to the WSAB’s advisory opinion that had not been incorporated into the WMP. Instead of bringing it before the City Council for approval as is, staff opted to remove the item from consideration in order to provide an updated 2021 Riverside Public Utilities WMP to the Riverside Board for approval again. The update to the 2021 Riverside Public Utilities WMP was approved on September 27, 2021 and October 12, 2021 by the Riverside Board and City Council, respectively.

On June 27, 2022, the Riverside Board approved the 2022 WMP which was then submitted to the WSAB on June 30, 2022. On October 17, 2022, the WSAB issued a guidance advisory opinion for the 2023 WMP for electric POUs and rural electric cooperatives. The advisory opinion included general guidance that applied to all POUs, specific guidance for each POU, and a template with instructions for preparing 2023 plans. All guidance was incorporated into Riverside’s 2023 WMP. The 2023 WMP included the steps, programs, policies, and procedures implemented by the Electric System to reduce wildfire risks and minimize impacts to customers. As required by PUC Section 8387, a qualified independent evaluator was contracted to review and assess the 2023 WMP for comprehensiveness. The independent evaluator provided feedback on the plan, which the Electric System incorporated by including additional details to further clarify the Electric System’s wildfire mitigation measures. Afterwards, the independent evaluator concluded that the Electric System’s 2023 WMP was sufficient in meeting the requirements for comprehensiveness. On June 26, 2023 and July 18, 2023, the 2023 WMP and independent evaluator’s

findings were presented to the Riverside Board and City Council, respectively. The 2023 WMP was submitted to the WSAB on July 19, 2023.

The 2024 WMP was not required to be a comprehensive revision and therefore did not require an independent evaluator review. On June 10, 2024, the Riverside Board recommended approval of the 2024 WMP and on June 18, 2024, the City Council approved the 2024 WMP. The 2024 WMP was submitted to the WSAB on July 1, 2024.

On June 9, 2025, the Board recommend that the City Council approve the Riverside Public Utilities Department's 2025 WMP. On June 24, 2025, City Council approved the Riverside Public Utilities Department's 2025 WMP for submittal to the WSAB. On June 25, 2025, the 2025 WMP was submitted to the WSAB as a comprehensive revision and therefore did not require an independent evaluator review.

For the wildfire fund, only voluntarily participating IOUs are eligible for claims arising from a covered wildfire. The POUs are not required nor able to join due to concerns and issues over complications of funding as a public entity. The bills do not address existing legal doctrine relating to utilities' liability for wildfires. However, any future legislation that addresses California's inverse condemnation and strict liability issues for utilities in the context of wildfires could be significant for the Electric System. Riverside is regularly engaged with the current WSAB meetings and updates, continues to partner with the Riverside Fire Department, and is diligently monitoring the outcome and impacts of any upcoming legislation and regulations on its service territory and ratepayers.

Assembly Bill 205 – On-call Resources and Energy Storage. On June 30, 2022, AB 205 was signed into law to address several energy topics but more specifically, on-call emergency supply and load reduction for the State's electrical grid during extreme events to reduce the risk of blackouts. AB 205 requires the CEC to implement and administer the Distributed Electricity Backup Assets (DEBA) program to incentivize the construction of cleaner and more efficient distributed energy assets and the Demand Side Grid Support ("DSGS") program to incentivize dispatchable customer load reduction and backup generation operation to be on-call for extreme events.

The initial DSGS program and guidelines launched in the Summer of 2022 and concluded October 2022. On July 26, 2023, the CEC adopted the second edition of the DSGS guidelines, which made the program effective immediately. On May 8, 2024, the CEC adopted the DSGS Guidelines, Third Edition. Through the program, participating customers receive a financial incentive for on-call load reduction during extreme events and the Electric System receives reimbursement for administrative costs to facilitate customer participation. The funding for the DSGS program was authorized by AB 205 and further expanded by AB 102 (signed on July 10, 2023), which stated the funding would be available for five years until June 30, 2027. On May 13, 2024 and June 11, 2024, the recommendation for the Electric System to allow customers to participate in a non-utility sponsored demand response program under the CEC DSGS State program was approved by the Riverside Board and City Council, respectively. Following these approvals, the Electric System began authorization of enrolling customers in the CEC DSGS program. On April 10, 2025, the CEC adopted the DSGS Guidelines, Fourth Edition. The new guidelines did not affect the Electric System's participation in the program.

On January 27, 2023, the CEC held a workshop to discuss the DSGS program and the DEBA program. Information from this meeting was used to inform the development of the DEBA program. Proposed DEBA guidelines were released on August 11, 2023, and were approved on October 18, 2023. The guidelines set aside 25% of program funding for projects in POU territories, which would be awarded through grant funding opportunity solicitations. In December 2023, the first DEBA grant funding opportunity was released for bulk grid asset enhancements focused on grid reliability. This program could potentially provide funding to the Electric System for additional bulk grid assets and/or distributed resources.

The Electric System will continue to monitor upcoming workshops and regulations for funding opportunities and any impacts on its service territory and ratepayers.

Assembly Bill 209 – Energy and Climate Change. On September 6, 2023, AB 209 was signed into law authorizing several energy programs to address climate change. One program is the Equitable Building Decarbonization Program. The program provides funding for a Statewide Direct Install Program, Tribal Direct Install Program, and a Statewide Incentive Program, and provides support for existing programs. This program must serve under-resourced communities and can fund eligible measures such as heating and cooling, building envelope retrofits, water heating, cooking, and more. The program guidelines were adopted on October 18, 2024, and the program administrators were selected in August 2024. In January 2025, the Department of Energy approved the CEC’s Homeowner Managing Energy Savings program proposal. A portion of the funding received for this proposal will support the Equitable Building Decarbonization Direct Install program. The program is expected to roll out to initial communities in winter 2025.

AB 209 also established directives for allocating general funds to provide incentives for eligible residential customers, including publicly owned utility (“POU”) customers, for the Self-Generation Incentive Program (“SGIP”). SGIP provides incentives to support existing, new, and emerging distributed energy resources installed on the customer’s side of the utility meter. Qualifying technologies include wind turbines, fuel cells, advanced energy storage systems and more. On July 10, 2023, the Governor approved SB 123, clarifying that SGIP incentives are eligible for low-income residential customers who install behind-the-meter energy storage or photovoltaic systems. It also clarified that these incentives are available to POU customers.

Another program under AB 209 that the CEC must establish and administer is the Hydrogen Program to provide financial incentives to in-state hydrogen projects for the demonstration or scale-up of the production, processing, delivery, storage, or end use of clean hydrogen. The CEC held a workshop in December 2022 to provide an overview of the Clean Hydrogen Program and the proposed program scope, funding areas, and project requirements. On May 19, 2023, the CEC released a draft solicitation concept for large-scale centralized production to solicit public feedback. On May 23, 2023, the CEC released the “Cost Share for Federal Clean Energy Funding Opportunities” competitive solicitation, which is ongoing. In May 2024, Governor Newsom released the 2024-2025 Revised State Budget Proposal, which called for reducing the Clean Hydrogen Program funding to \$40 million and delaying the majority of funding until Fiscal Year 2025-2026.

The Electric System will continue to monitor the development of these programs to determine opportunities and impacts on its service territory and ratepayers.

Senate Bill 48 – Building Energy Savings Act. On October 7, 2023, the Governor signed into law the Building Energy Savings Act (SB 48). This bill requires the CEC, in consultation with CARB, CPUC, and Department of Housing and Community Development, on or before July 1, 2026, to develop a strategy for using the energy usage data collected from the benchmarking and disclosure program developed through AB 802. The CEC intends to develop a report that reflects the strategy and recommendations to track and manage the building energy usage and associated GHG emissions to achieve the State’s equity, energy and emission goals, targets, and standards. The bill requires the CEC to submit the strategy and recommendations to the Legislature on or before August 1, 2026.

On July 31, 2024, the CEC held a workshop to kick off the development of the California Building Energy Performance Strategy Report to also include recommendations for further legislative action. The Electric System will continue to monitor the progress of the report for impacts on its service territory and ratepayers.