

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

**Relating to:**

**\$26,585,000 Southern California Public Power Authority  
Tieton Hydropower Project, Revenue Refunding Bonds, 2020 Series A (Green Bonds)**

**INTRODUCTION**

This Annual Report is filed pursuant to the Continuing Disclosure Resolution (Resolution No. 2020-029), adopted by the Southern California Public Power Authority (the “Authority” or “SCPPA”) on April 16, 2020 (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 May 14, 2020 (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 City of Burbank, California (“Burbank”) and the City of Glendale, California (“Glendale,” and together with Burbank, the “Participants” and, individually, a “Participant”) make no representation that this Annual Report contains all information material to a decision to purchase or sell any of the Bonds.

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

**THE TIETON HYDROPOWER PROJECT**

**General Description**

The Tieton Hydropower Project is a “run of the reservoir” hydroelectric facility, comprised of a powerhouse constructed at the base of the U.S. Bureau of Reclamation’s (the “Bureau”) Tieton Dam on the Tieton River in the State of Washington, and a 21-mile 115 kV transmission line from the power plant substation to the point of interconnection with the electrical grid. The Tieton Hydropower Project powerhouse is located near Rimrock Lake in Yakima County approximately 40 miles west of the city of Yakima, Washington, lies entirely within property owned by the United States and is incorporated into the existing outlet foundation of the Bureau’s Tieton Dam. The powerhouse, comprised of two Francis turbines and accompanying generators, has a nameplate capacity of 13.6 MW, with a maximum capacity of approximately 20 MW. The powerhouse began commercial operation on September 5, 2006. The powerhouse is deemed a “small power production facility” (nameplate capacity of 20 MW or less) by the

Federal Energy Regulatory Commission. Average annual generation from the Tieton Hydropower Project is approximately 50,000 MWhs. The Tieton Hydropower Project was acquired by the Authority from Tieton Hydropower, L.L.C., a Washington limited liability company (hereinafter, “Tieton”), pursuant to an Asset Purchase Agreement, dated as of October 19, 2009 (the “Asset Purchase Agreement”), by and between the Authority and Tieton Hydropower, L.L.C.

The Tieton Hydropower Project facilities also include a 21-mile, 115 kV transmission line (hereinafter, the “Transmission Line”) that runs from the Tieton Dam Rimrock Substation, located adjacent to the powerhouse and approximately 300 feet to the northeast of the dam, to the PacifiCorp Tieton Substation owned by PacifiCorp. The Transmission Line crosses federal government land (U.S. Forest Service (“USFS”) and Bureau), Washington State-owned land (Washington Department of Fish and Wildlife (“WDFW”), Washington Department of Natural Resources (“DNR”) and Washington State Department of Transportation (“WSDOT”)), Yakima County rights-of-way, and privately-owned lands, and is operated and maintained by the Benton Rural Electric Association (“BREA”) pursuant to various agreements with Tieton. USFS manages the property surrounding the Tieton Hydropower Project under two special use permits for construction and operation of the Tieton Substation and the Transmission Line. Pursuant to a collection agreement with the USFS, Tieton was obligated to fund certain construction activities and to maintain existing recreation facilities and resource protection for a 24-year period, which obligation has been assumed by the Authority.

The Transmission Line is composed of two segments: the line running approximately 11 miles from the Tieton Hydropower Project powerhouse to a point referred to as “Jump-Off Joe,” and the line from Jump-Off Joe to the PacifiCorp Tieton Substation. The segment of the line between the powerhouse and Jump-Off Joe is known as the joint use segment. The joint use segment was built on an existing right-of-way for a 34.5 kV line owned by BREA and crosses USFS land, Bureau land, WDFW land, DNR land, WSDOT rights-of-way and several privately-owned lands. The BREA 34.5 kV line poles were removed and the Transmission Line was re-built as a new 115 kV pole line with the BREA underbuilt 34.5 kV lines attached. Approximately 10 miles of the 115 kV Transmission Line from Jump-Off Joe to the PacifiCorp Tieton Substation are located on rights-of-way on property owned by USFS, several private landowners and Yakima County. Tieton filed an application with FERC for removal of the Transmission Line from FERC jurisdictional property, which application was granted on September 30, 2009 in connection with the acquisition of the Tieton Hydropower Project by the Authority.

From the PacifiCorp Tieton Substation, PacifiCorp transmission lines take the energy from the Tieton Hydropower Project to the Mid-C market-hub, and on the Bonneville Power Administration system to Big Eddy, the northern terminus of the Pacific Northwest DC Intertie, from which it is then transmitted to the Nevada-Oregon border on the Pacific Northwest DC Intertie, a point from which the Participants are able to transmit the energy to their respective electric service areas using their existing transmission rights.

## **Operation of the Tieton Hydropower Project**

The Bureau owns and operates the dam and controls the flow into the Tieton River from the Rimrock Lake reservoir created by the dam. The Tieton Hydropower Project was developed to capture energy from water released through the dam for irrigation or riparian flow requirements. Due to the seasonal flow variations and the priority assigned to irrigation operations, the Bureau does not release water to the Tieton Hydropower Project during winter months and the energy production at the Tieton Hydropower Project occurs mainly during the months of May through October.

Upon acquisition of the Tieton Hydropower Project, Burbank acting in its capacity as agent for the Authority, entered into a services agreement with Energy Northwest to operate and provide routine maintenance of the Tieton Hydropower Project. The services agreement had an initial term of two years with an expiration date of June 30, 2017, with the option for multiple extensions. On July 2018, the contract was amended for one additional year from July 1, 2018 to June 30, 2019 with an option to renew on an

annual basis for up to four additional years. In 2023, the agreement was amended to allow for ten additional years and remains active through June 30, 2033.

**Annual Operating Budget**

Set forth below is a summary of the Tieton Hydropower Project operating budget for the fiscal year ending June 30, 2026:

**Southern California Public Power Authority  
Tieton Hydropower Project  
Fiscal Year 2025-26 Operating Budget  
(\$ in 000's)**

<b>Description</b>	<b>Amount</b>
Net Debt Service (estimated)	\$2,448
Project Manager	228
Operating Expense	2,580
Authority A&G	<u>276</u>
Total	<u>\$5,532</u>
Estimated MWs	42,696
Estimated Cost/kWh	\$0.130

**Operations of the Tieton Hydropower Project**

In the fiscal year ending June 30, 2025, the Tieton Hydropower Project generated 19,075 MWs at a cost of \$7,541,000 (\$0.395/kWh).

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

**Southern California Public Power Authority  
Tieton Hydropower Project  
Operating Statistics**

	<b>2020-21</b>		<b>2021-22</b>		<b>2022-23</b>		<b>2023-24</b>		<b>2024-25</b>	
	<b>Budget</b>	<b>Actual</b>	<b>Budget</b>	<b>Actual</b>	<b>Budget</b>	<b>Actual</b>	<b>Budget</b>	<b>Actual</b>	<b>Budget</b>	<b>Actual</b>
Net Debt Service	\$3,336,000	\$2,798,000	\$2,808,000	\$2,803,000	\$2,796,000	\$2,701,000	\$2,712,000	\$2,586,000	\$4,248,000	\$4,144,000
Project Manager	108,000	652,000	120,000	559,000	120,000	606,000	120,000	776,000	132,000	752,000
Operating Expense	3,732,000	2,934,000	2,616,000	1,334,000	2,496,000	1,710,000	2,292,000	1,366,000	2,412,000	2,452,000
Authority A&G	216,000	177,000	180,000	150,000	168,000	148,000	168,000	180,000	192,000	193,000
<b>Total</b>	<b>\$7,392,000</b>	<b>\$6,561,000</b>	<b>\$5,724,000</b>	<b>\$4,846,000</b>	<b>\$5,580,000</b>	<b>\$5,165,000</b>	<b>\$5,292,000</b>	<b>\$4,908,000</b>	<b>\$6,984,000</b>	<b>\$7,541,000</b>
Estimated MWs	48,495	42,170	48,495	54,307	47,300	47,259	48,000	33,306	47,093	19,075
Estimated Cost per kWh	\$0.152	\$0.156	\$0.118	\$0.089	\$0.118	\$0.109	\$0.110	\$0.147	\$0.148	\$0.395

## Certain Financial Statements Relating to the Tieton Hydropower Project

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

### Southern California Public Power Authority Tieton Hydropower Project Statement of Net Position (In Thousands)

	<b>Fiscal Year Ended June 30,</b>	
	<b>2025</b>	<b>2024</b>
<b>ASSETS</b>		
Noncurrent assets		
Net utility plant	\$26,524	\$28,003
Investments – restricted	<u>3,820</u>	<u>2,420</u>
Total noncurrent assets	<u>30,344</u>	<u>30,423</u>
Current assets		
Cash and cash equivalents – restricted	1,947	1,762
Cash and cash equivalents – unrestricted	207	1,057
Interest receivable	5	6
Accounts receivable	557	-
Prepaid and other assets	<u>4</u>	<u>3</u>
Total current assets	<u>2,720</u>	<u>2,828</u>
<b>DEFERRED OUTFLOWS OF RESOURCES</b>		
Reclamation and decommissioning obligation	<u>342</u>	<u>365</u>
Total deferred outflows of resources	<u>342</u>	<u>365</u>
Total assets and deferred outflows of resources	<u>\$33,406</u>	<u>\$33,616</u>
<b>LIABILITIES</b>		
Noncurrent liabilities		
Long-term debt	\$30,586	\$34,085
Reclamation and decommissioning obligation	<u>1,075</u>	<u>1,046</u>
Total noncurrent liabilities	<u>31,661</u>	<u>35,131</u>
Current liabilities		
Debt due within one year	2,915	1,300
Advances from participants due within one year	202	202
Accrued interest	715	752
Accounts payable and accruals	<u>407</u>	<u>701</u>
Total current liabilities	<u>4,239</u>	<u>2,955</u>
Total liabilities	<u>35,900</u>	<u>38,086</u>
<b>DEFERRED INFLOWS OF RESOURCES</b>		
Unamortized gain on refunding	<u>395</u>	<u>439</u>
Total deferred inflows of resources	<u>395</u>	<u>439</u>

**NET POSITION**

Net investment in capital assets	(7,372)	(7,821)
Restricted	4,325	2,753
Unrestricted	<u>158</u>	<u>159</u>
Total net position	<u>(2,889)</u>	<u>(4,909)</u>
Total liabilities, deferred inflows of resources and net position	<u>\$33,406</u>	<u>\$33,616</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 fiscal years ended June 30, 2025 and June 30, 2024.

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

	<u>Fiscal Year Ended June 30,</u>	
	<u>2025</u>	<u>2024</u>
Operating revenues:		
Sales of electric energy	\$7,541	\$4,908
Total operating revenues .....	<u>7,541</u>	<u>4,908</u>
Operating expenses:		
Operations and maintenance .....	3,400	2,325
Depreciation, depletion, and amortization .....	1,479	1,498
Decommissioning .....	<u>23</u>	<u>23</u>
Total operating expenses .....	<u>4,902</u>	<u>3,846</u>
Operating income .....	<u>2,639</u>	<u>1,062</u>
Non-operating revenues (expenses)		
Investment and other income .....	210	228
Inflation of decommissioning liability .....	(28)	(30)
Other interest and debt expense .....	<u>(801)</u>	<u>(877)</u>
Net non-operating revenues (expenses) .....	<u>(619)</u>	<u>(679)</u>
Change in net position .....	2,020	383
Net position – beginning of year	<u>(4,909)</u>	<u>(5,292)</u>
Net position – end of year .....	<u>\$(2,889)</u>	<u>\$(4,909)</u>

**ESTIMATED DEBT SERVICE REQUIREMENTS FOR THE BONDS  
(Cash Basis)**

Year Ending July 1	2020 Series A Bonds		Total <sup>(1)</sup>
	Principal	Interest	
2026	\$ 1,235,000	\$1,260,000	\$2,495,000
2027	1,300,000	1,198,250	2,498,250
2028	1,360,000	1,133,250	2,493,250
2029	1,430,000	1,065,250	2,495,250
2030	1,500,000	993,750	2,493,750
2031	1,575,000	918,750	2,493,750
2032	1,655,000	840,000	2,495,000
2033	1,740,000	757,250	2,497,250
2034	1,825,000	670,250	2,495,250
2035	1,920,000	579,000	2,499,000
2036	2,010,000	483,000	2,493,000
2037	2,110,000	382,500	2,492,500
2038	2,220,000	277,000	2,497,000
2039	2,305,000	188,200	2,493,200
2040	<u>2,400,000</u>	<u>96,000</u>	<u>2,496,000</u>
Total <sup>(1)</sup>	<u>\$26,585,000</u>	<u>\$10,842,450</u>	<u>\$37,427,450</u>

<sup>(1)</sup> Totals may not add due to rounding.

## **FINANCIAL STATEMENTS**

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

### **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.

## CITY OF BURBANK

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

### General

Burbank was incorporated as a general law city in 1911, adopted its City Charter in 1927, and is administered by a Council-Manager form of government. Burbank’s estimated population as of January 1, 2025 was 106,146, according to the California Department of Finance. Burbank is located in the greater metropolitan Los Angeles area, approximately 12 miles northeast of the Los Angeles Civic Center complex. Burbank’s Public Service Department was established in 1913 under the laws of the State of California to supervise the generation, purchase, distribution and sale of electricity and the purchase, distribution and sale of water. In 2000, the name of the Public Service Department was changed to Burbank Water and Power (“BWP”). BWP provides service to all electric and water customers within Burbank. Burbank owns and operates an integrated Electric System, which includes generation, transmission and distribution facilities, and a water system (the “Water System”).

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.

For the Fiscal Year ended June 30, 2025, Burbank currently estimates the average number of customers of the Electric System was approximately 53,628 and the total megawatt hours (“MWh”) of energy sold to customers throughout Burbank was approximately 961,401 MWhs.

### Management

BWP is under the direct management of the BWP General Manager, subject to the policy and direction of the Burbank City Council and the Burbank Water and Power Board (the “BWP Board”) and the broad administrative direction of the City Manager. The BWP Board consists of seven members appointed by the Burbank City Council. The BWP General Manager is responsible for policy and planning relating to the operation of both the Electric System and Water System. Legal services are provided by the City Attorney’s office, and various administrative services are also provided by the City. Senior Management of the Electric System includes:

***Mandip Samra***, General Manager, holds a Bachelor of Arts in Economics from University of California, Los Angeles, a Master of Public Administration from The Maxwell School of Citizenship and Public Affairs at Syracuse University, and a Master of Urban Planning from the University of Southern California. Ms. Samra joined BWP in March 2021 and was promoted to General Manager in May 2024. She started her career as a Graduate Management Intern in the Customer Relations Division of Pasadena Water and Power in 2004. Prior to joining BWP, she worked in various management positions at Anaheim Public Utilities, Southern California Edison, and Pasadena Water and Power. Her experience in power supply ranges from regulatory compliance, managing the integrated resources plan, negotiating power resource contracts, representing the utility on various resource and transmission committees, and leading stakeholder engagement efforts as it relates to power supply.

***Riad Sleiman, P.E., PMP***, Chief Assistant General Manager/Electric Services, holds a Bachelor of Science in Electrical Engineering from Loyola Marymount University and a Master of Business Administration from Woodbury University. Mr. Sleiman originally joined BWP in 2005 as an Electrical Engineering Assistant working on street lighting, major development reviews, project management, system

(Burbank 2025 R. 15c2-12)

planning, development agreements and contract negotiations, advanced metering infrastructure deployment, and advanced grid analytics. He then worked on utility-scale battery storage, electric vehicle infrastructure planning, and deployment, implementing small cell policy and agreements, and introducing analytics and applications through the GIS and records group while at the City of Santa Clara electric utility (dba Silicon Valley Power). Mr. Sleiman rejoined BWP in 2021 as the Assistant General Manager/Electric Services. He is a licensed Electrical Engineer in the State of California and is a certified Project Management Professional.

**Joseph Lillio**, Chief Financial Officer (“CFO”), holds a Bachelor of Science in Business Administration with an option in accounting from California State University, Los Angeles and a Master of Public Administration with an option in public sector management and leadership from California State University, Northridge. Mr. Lillio joined BWP in May 2023. Mr. Lillio came to Burbank from the City of El Segundo where he served as the CFO for over seven years. Prior to that, he served in various leadership roles at the City of Oxnard, Las Virgenes Municipal Water District, City of San Fernando, and City of Santa Clarita. He has over 20 years of experience in municipal finance which includes water, wastewater, solid waste, and electric utilities. He also has seven years of private sector finance experience working in the corporate finance office for Princess Cruises.

**Erik Olsen**, Acting Assistant General Manager/Power Supply, holds a Bachelor of Science in Electrical Engineering from the University of California, Los Angeles. He is a registered Professional Engineer in the State of California with over 20 years of experience in the electric industry. Mr. Olsen joined BWP in June 2014 and has served in various roles, most recently as the Manager of the Energy Control Center and Principal Electrical Engineer in Electric Services for the Substation Engineering group. His career began as an Electrical Engineering Assistant with Glendale Water and Power in 2003, where he held several engineering and management positions. His expertise spans North American Electric Reliability Corporation (NERC) compliance, system planning, engineering, operations, and utility management.

## **Principal Facilities**

The service area of the Electric System is solely within Burbank’s boundaries, which encompasses 17.1 square miles. The principal facilities of the Electric System consist of two natural gas-fired steam electric generating units, one natural gas-fired combustion turbine electric generating unit, four microturbine electric generating units, four switching stations, 12 distributing stations, two customer stations and transmission and distribution lines aggregating approximately 411 circuit miles.

## **Power Distribution**

Burbank interconnects its electric facilities with other electric utilities through an 806 million volt-amperes (“MVA”) tie to the Los Angeles Department of Water and Power (“LADWP”) at Receiving Station “E” as well as a 191-megawatt (“MW”) tie with Glendale Water and Power. Presently, these ties have more than sufficient capacity to import enough power to meet Burbank’s system load as well as to export power to the participants in the Magnolia Power Project. Burbank acts as the operating agent for the Magnolia Power Project and is responsible for operating the Magnolia Power Project on behalf of the Southern California Public Power Authority (“SCPPA” or the “Authority”).

Within Burbank, bulk power is transformed from 69 kilovolts (“kV”) to 34.5 kV by four switching stations interconnected with nearly 34 circuit miles of 69 kV lines. There are about 44 circuit miles of 34.5 kV lines that interconnect the switching stations with 12 distributing stations and two customer stations. Burbank has about 102 distribution circuits and 5,865 distribution transformers to serve residential neighborhoods and businesses. Burbank’s distribution system includes about 136 distribution circuit miles of underground lines and 200 circuit miles of overhead lines.

(Burbank 2025 R. 15c2-12)

## **Insurance**

Burbank is self-insured and self-administered for certain exposures through Risk Management & Safety, a division of the Management Services Department of the City. Burbank is self-insured for individual claims up to \$2,000,000 for worker's compensation, and \$1,000,000 for general liability. Since July 1, 2004, the City has been a member in Authority for California Cities Excess Liability (ACCEL), which is a risk sharing pool for municipal excess general liability. Each individual member self-insures all general liability losses for the first \$1,000,000 and the members of the pool share losses between \$1,000,000 and \$10,000,000. The members jointly purchase additional layers of coverage beyond the pooled layer, with Burbank purchasing an additional \$55,000,000 of excess coverage, for total coverage of \$65,000,000. The layers of coverage above \$10,000,000 are not pooled, but rather jointly purchased. The City self-insures its worker's compensation coverage for the first \$2,000,000 of each loss, and the City purchases excess coverage up to statutory limits. The City charges the Electric Fund based upon the proportional payroll cost, job classification, and claim history. There have been no significant settlements or reductions in insurance coverage for the past three years. The City maintains a \$10,000,000 flood insurance policy. The City does not currently maintain insurance coverage for the Electric System for earthquake or wildfire risks.

## **Power Supply - General**

BWP currently meets its Electric System power requirements from a combination of on-site gas-fired generating facilities, power purchase agreements, firm contracts and non-firm energy purchases. Among such resources, Burbank purchases power from the Intermountain Power Project ("IPP") of the Intermountain Power Agency ("IPA"), the Hoover Upgrading Project, Powerex Corp. for Portfolio Content Category 1 ("PCC 1") and 2 ("PCC 2") renewable energy, Tule Hydro for PCC 1 renewable energy and had a power exchange agreement with Morgan Stanley Capital Group Inc. ("Morgan Stanley"). PCC 1 is the highest quality renewable energy credit associated with renewable energy in the California Energy Commission's Renewable Portfolio Standards program. In order to count as PCC 1, the renewable energy must be produced in California (or directly delivered into a California balancing authority area), as produced, without any substitute energy from any other sources. PCC 2 is renewable energy credit associated with renewable energy generated outside of California and imported into the state in the California Energy Commission's Renewable Portfolio Standards program. It is a firm/ed/shaped energy product where the equivalent amount of energy from a non-renewable source is delivered to California and bundled with renewable energy credit. Additionally, through its membership in SCPPA, Burbank has entitlement interests in the Palo Verde Nuclear Generating Station ("PVNGS"), Milford Phase I Wind Project, Tieton Hydropower Project and Magnolia Power Project, and purchases power from the Copper Mountain Solar 3 Project, Don A. Campbell Geothermal Project, Ameresco Chiquita Canyon Landfill Gas Project, Pebble Springs Wind Project and Desert Harvest II Solar Project. See "On-Site Resources," "Non-Burbank Owned Resources" and "Renewable Energy Resources" below.

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

During the Fiscal Year ended June 30, 2025, the Electric System generated and purchased (exclusive of purchases and sales for wholesale purposes) approximately 1,009,790 MWh of electricity for delivery to customers throughout Burbank. The following table sets forth the amounts, in MWhs and

percentages, of electricity obtained by Burbank from its current resources for sales to customers throughout Burbank during the Fiscal Year ended June 30, 2025.

**Burbank Water and Power  
Annual Retail Electric Supply  
Fiscal Year Ended June 30, 2025**

<b>Resource</b>	<b>MWh</b>	<b>Percentage</b>
Renewables <sup>(1)</sup> .....	508,470	50.4%
Magnolia Power Project .....	100,970	10.0
Intermountain Power Project .....	174,050	17.2
Spot Purchases .....	161,970	16.0
Palo Verde Nuclear .....	34,380	3.4
Hoover Upgrading .....	12,070	1.2
On-Site Generation .....	17,880	1.8
Total <sup>(2)</sup>	1,009,790	100.0%

<sup>(1)</sup> Renewable resources include the Milford Phase I Wind Project, Tieton Hydropower Project, Pebble Springs Wind Project, Ameresco Chiquita Canyon Landfill Gas Project, Copper Mountain Solar Project, Don A. Campbell Geothermal Project, Desert Harvest II Solar Project, Powerex Corp. purchase of renewable energy, spot renewable energy credits, local generation from BWP Valley Pumping Plant, local landfill microturbines, customer and utility solar installations, and an exchange agreement. See “– Renewable Energy Resources.” For the Fiscal Year ended June 30, 2025, renewable energy resources made up approximately 52.9% of Burbank’s total retail sales. This number differs from the official Renewable Portfolio Standard (RPS) calculation and compliance period, which are based on retail sales and calendar year.

<sup>(2)</sup> Does not equal total sales to customers throughout Burbank of approximately 961,401 MWh due to distribution losses and timing differences in billing cycles between sales to customers, purchased energy, and renewable energy credits. Totals may not add due to rounding.

Source: BWP.

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## On-Site Resources

Burbank owns two steam electric generating units with a total combined net capacity of 99 MW (with a nameplate capacity of 109.7 MW), one combustion turbine electric generating unit with a total continuous net capacity of 48 MW (with a nameplate capacity of 60.5 MW), and four microturbine electric generating units with a total combined net capacity of 0.5 MW (with a nameplate capacity of 0.8 MW) as indicated in the following table:

### On-Site Generation Owned by Burbank Water and Power

Unit Name	Type	Nameplate Capacity (MW)	Continuous Capacity (MW)	Year In-service	Energy Produced in Fiscal Year 2024-25 (MWh)
Olive 1 <sup>(1)</sup>	Steam	50.0	44.0	1959	0
Olive 2 <sup>(1)</sup>	Steam	59.7	55.0	1964	0
Lake 1	Combustion Turbine	60.5	48.0	2002	12,066
Landfill	Microturbines	0.8	0.5	2020	4,155
Total		171.0	147.5		16,221

<sup>(1)</sup> Olive 1 and 2 were used as planning capacity and serve as backup or emergency generation capacity.  
Source: BWP.

## Non-Burbank Owned Resources

Burbank purchases power and transmission capability from other sources pursuant to contracts. These contracts provide generally for Burbank to pay costs associated with the firm purchase of power (including fixed components like operations, maintenance and administrative expenses as well as variable components like fuel expenses). With respect to each of the facilities discussed herein, Burbank is one of any number of purchasers of such power and, with the exception of Magnolia Power Project and the Tieton Hydropower Project, does not control the operations or management of such facility. See also “Indebtedness; Joint Powers Agency Obligations” below.

**Intermountain Power Project.** Until November of 2025, the IPP consisted of: (a) a two-unit coal-fired, steam-electric generating plant with net ratings of 900 MW per unit (the “Intermountain Generating Station”) and switchyard (the “Switchyard”), located near Lynndyl, in Millard County, Utah; (b) a ±500 kV direct current (“DC”) transmission line approximately 490 miles in length from and including the Intermountain Converter Station (an alternating current (“AC”)/DC converter station adjacent to the Switchyard) to and including a corresponding converter station at Adelanto, California (collectively, the “Southern Transmission System” or “STS”) (see “Transmission Resources – Southern Transmission Project” below); (c) two 50-mile, 345 kV AC lines from the Switchyard to the Mona Substation in the vicinity of Mona, Utah, and a 144-mile, 230 kV AC transmission line from the Intermountain AC Switchyard to the Gonder Substation near Ely, Nevada (collectively, the “Northern Transmission System” or “NTS”); (d) a microwave communications system; (e) a rail car service center located in Springville, in Utah County, Utah (the “Railcar Service Center”); and (f) certain water rights and coal supplies. Such water rights and coal supplies, together with the Intermountain Generating Station, the Switchyard and the Railcar Service Center, are referred to herein collectively as the “Generation Station.” As of November 26, 2025, the coal generators have been taken out of service and no longer operates for the IPP purchasers’ needs. They have been replaced with two natural gas generators, and BWP no longer has coal in its resource portfolio.

(Burbank 2025 R. 15c2-12)

IPP purchasers are 35 utilities (collectively, the “IPP Purchasers”) consisting of Burbank and the California cities of Anaheim, Los Angeles, Riverside, Glendale and Pasadena (the “IPP California Participants”); the 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”). After June 2027, the cities of Anaheim, Riverside and Pasadena will not be part of the project. Pursuant to a construction management and operation agreement between IPA and LADWP, LADWP acts as project manager and operating agent of the IPP, responsible for, among other things, administering, operating and maintaining the IPP. The facilities of the IPP have been in commercial operation since May 1987.

The IPP Generation Station also represents Burbank’s only source of electricity generated by coal-fired plants. The power purchase contract with IPA obligates Burbank 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 Burbank.

Transmission of the output from IPP to Burbank and the other IPP California Participants is provided by the STS. The STS was placed in operation in May 1987, and its current transfer capability is 2,400 MW. See “Transmission Resources – Southern Transmission Project” below. Burbank and SCPPA have entered into a transmission service contract to provide for transmission of Burbank’s entitlement between the Generating Station and Adelanto. Transmission service from Adelanto to Burbank is provided under transmission service agreements with LADWP.

Senate Bill 1368 (“SB 1368”), which became effective in January 2007, prohibits any investment in baseload generation that does not meet specific emissions performance standards, subject to certain exceptions. In light of the restriction, the coal-powered generation facility has been replaced by combined cycle natural gas units (the “IPP Repowering Project”), which have reached Firm Operations as of December 4, 2025 and will allow for compliance with greenhouse gas emissions (“GHG”) performance standards. The total cost of the IPP Repowering Project is estimated to be \$4.96 billion. The IPP Repowering Project includes hydrogen betterments, gas pipeline, generation and decommissioning costs, and the STS Renewal Project (as defined and described in “– Transmission Resources – *Southern Transmission Renewal Project*”). Approximately half, or \$2.5 billion, of the total IPP Repowering Project cost is for the STS Renewal Project, and the City’s share of such cost is 4.22%. The City’s share of the remaining estimated \$2.46 billion IPP Repowering Project cost is 3.33%. The existing power sales contracts will terminate on June 15, 2027 and will be replaced by renewal power sales contracts (“IPA Renewal Power Sales Contracts”) (which were executed in 2017) for the combined cycle natural gas units, which will continue for a term ending in 2077. The City will be obligated to pay for the capacity and energy purchased under its IPA Renewal Power Sales Contract on a “take-or-pay” basis as operating expenses of the Electric System, including principal of debt issued for the project, capital costs and costs related to operation and maintenance. See “– Indebtedness; Joint Powers Agency Obligations – *Joint Powers Agency Obligations*.” Based on the most recent study (conducted in 2019) available to the City, the City expects that its proportionate share of the cost of decommissioning the coal-powered generation facility to be approximately \$14 million. Pursuant to the provisions of the IPA Renewal Power Sales Contracts, the IPP participants also agreed to reduce the initially planned generation capacity for the repowered plant from 1,200 MW to 840 MW. Some of the power purchasers under the original power sales contracts will continue to be IPP participants under the IPA Renewal Power Sales Contracts. The cities of Anaheim, Riverside, and Pasadena will not be power purchasers under the IPA Renewal Power Sales Contracts. The City will take a smaller share of 28 MW generation capacity (3.334%) under the IPA Renewal Power Sales Contracts, and LADWP and the City of Glendale will both increase their respective generation shares. These units are capable of being powered by 30% green hydrogen, with an aim for 100% green hydrogen (i.e. hydrogen created solely by use of renewable energy) by 2045. Burbank has the option, however does not have the obligation, to become a hydrogen purchaser, and to participate in the use of hydrogen at the project. To date, Burbank has not participated in the production of hydrogen.

(Burbank 2025 R. 15c2-12)

IPA is working with participants to develop a plan to achieve the goal of reaching 100% green hydrogen fueled operation by 2045, pending the availability and the advancement of the required technology to reach those scales. IPA secured hydrogen storage facilities adjacent to the existing site. Such facilities use salt cavern storage capacity, along with energy conversion services. This provides the IPP participants the ability to convert renewable energy into green hydrogen to fuel the new generating units and is currently undergoing testing. LADWP is the only IPP participant that is required to purchase hydrogen under the conversion services agreement, however the City and Glendale each have the option to elect to become a hydrogen purchaser.

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. IPA now anticipates that the coal units will cease operation by December 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; and that if IPA had complied with Utah S.B. 161, as originally enacted, IPA may have been subject to enforcement actions that could have resulted 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 have interfered 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. 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 still working to determine the impact of Utah S.B. 161, as modified by Utah H.B. 3004, and to identify the appropriate course of action in response to the recent enactments. The City cannot predict the impacts of this legislation on the operation of IPP or the construction and 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, 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 is still assessing the potential impact of the appeal.

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.

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 Utah H.B. 70 and to identify the appropriate course of action in response to the recent enactments. These efforts are ongoing, and the City cannot predict the impacts of the new legislation on the operation of IPP or the construction and operation of the IPP Repowering Project.

***Hoover Upgrading Project.*** Burbank is a participant in the Hoover Upgrading Project, consisting primarily of the upgrading of the 17 generating units at the hydroelectric power plant of the Hoover Dam.

(Burbank 2025 R. 15c2-12)

Burbank has a 0.98% (20.325 MW) entitlement interest in the total capacity and allocated energy of Hoover. Burbank has executed a power sales contract and has agreed to make monthly payments in exchange for its share of Hoover capacity and allocated energy, which contract expires in 2067. The region where Hoover Dam and its hydroelectric facilities are located has been experiencing drought conditions for approximately 20 years. Hoover Dam can generate power when Lake Mead level is above 950 ft above sea level or higher. The operation of Hoover Dam is expected to continue until Lake Mead drops below the 950 ft minimum or additional water sources are available from upstream sources.

***Palo Verde Nuclear Generating Station (PVNGS).*** Through its membership in SCPPA, Burbank has a 4.40% entitlement interest (9.7 MW) in SCPPA's 5.91% ownership interest in PVNGS, including certain associated facilities and contractual rights, a 5.44% ownership in the Arizona Nuclear Power Project ("ANPP") High Voltage Switchyard and associated contractual rights, and a 6.55% share of the rights to use certain portions of the ANPP Valley Transmission System. Commercial operation and initial deliveries from PVNGS Units 1 and 2 commenced in 1986 and Unit 3 commenced in 1987. Transmission for PVNGS energy is provided to Burbank by the Mead-Adelanto Transmission Project and the Mead-Phoenix Transmission Project (see "Transmission Resources" below) and agreements with Salt River Project, LADWP and Southern California Edison Company.

Burbank has a power sales agreement with SCPPA which obligates Burbank to pay for its share of capacity and energy on a "take-or-pay" basis, including debt service on bonds issued by SCPPA for the project, capital costs and costs related to operation and maintenance.

The co-owners of PVNGS have created external accounts for the decommissioning of PVNGS at the end of its life. Decommissioning is expected to begin between 2045-2047. Based on the most recent estimate of decommissioning costs, SCPPA has advised Burbank that its estimated share of decommissioning costs through SCPPA is approximately 94% funded. Burbank's obligation is 4.4% of the cost, or approximately \$8.7 million, which is based on the most recent study that was conducted in 2019. No assurance can be given, however, that the amount accumulated to date will continue to be sufficient to fully fund SCPPA's share of decommissioning costs. SCPPA has advised Burbank that it anticipates it will receive a new estimate of decommissioning costs every three years.

***Magnolia Power Project.*** Burbank is a participant and the operating agent of SCPPA's Magnolia Power Project, a 323 MW natural gas-fired combined-cycle electrical power generating facility. The Magnolia Power Project is located in the city of Burbank and is owned by SCPPA. The Magnolia Power Project was constructed and acquired for the primary purpose of providing participants in the Magnolia Power Project with firm capacity and energy to help meet their power and energy requirements. Burbank has a 30.9917% entitlement (75 MW base capacity and 97.6 MW peaking capacity) in the project through a long-term power purchase agreement with SCPPA which obligates the City to pay for its share of capacity and energy on a "take-or-pay" basis, including debt service on bonds issued by SCPPA for the project, capital costs and costs related to operation and maintenance.

## **Renewable Energy Resources**

For the Fiscal Year ended June 30, 2025, the Electric System's renewable energy resources made up approximately 52.9% of its total retail sales. The Electric System is on track to meet the Renewables Portfolio Standard (RPS) of 46% for the calendar year 2025.

Burbank's renewable energy resources are described below.

***Milford Wind Corridor Phase I Project.*** Burbank is a participant in SCPPA's Milford Wind Corridor Phase I Project, providing for the purchase over a 20-year term of all of the energy generated by a 203.5 MW nameplate capacity, wind-powered electric generating facility located near Milford, Utah.

(Burbank 2025 R. 15c2-12)

Burbank entered into a Power Sales Agreement with SCPPA for 5.0% (approximately 10 MW) of the output (including capacity, energy and associated environmental attributes) of the Milford Wind Corridor Phase I Project. The facility is owned by Milford Wind Corridor Phase I, LLC, a limited liability company organized and existing under the laws of the State of Delaware. The facility went into commercial operation on November 16, 2009. Burbank is able to accept the delivered facility energy utilizing its capacity rights in the IPP Switchyard that are provided under agreements relating to the IPP. The facility energy is then delivered over the STS to the Adelanto terminal in California utilizing Burbank's capacity rights in the STS. The facility energy delivered at Adelanto is then transmitted to Burbank under certain transmission arrangements between LADWP and Burbank.

***Tieton Hydropower Project.*** Burbank is a participant in, and the operating agent of, SCPPA's Tieton Hydropower Project, a 13.6 MW nameplate capacity "run of the reservoir" hydroelectric generation facility located in the State of Washington. Burbank has entered into a power sales and acquisition contract with SCPPA, under which SCPPA has sold to Burbank on a "take-or-pay" basis, its entitlement of 50.0% (approximately 6.8 MW) of the capacity and energy of the Tieton Hydropower Project. Burbank's power sales and acquisition contract with SCPPA obligates Burbank to pay its share of debt service on bonds or notes issued by SCPPA for the project, as well as capital costs and costs related to operation and maintenance. Minor increases in the average annual and seasonal temperature in the Pacific Northwest are projected to continue as a result of global warming. However, projected changes in annual precipitation are expected to be very small. There has been no discernable impact to the project due to global warming to date. Tieton Hydropower Project averages about 48,000 MWhs of generation per year with slight annual variations attributable to year-to-year weather variations as well as changes in U.S. Bureau of Reclamation operations. For example, fish pulsing has had the greatest impact on water flow rates to the Tieton Hydropower Project.

***Pebble Springs Wind Project.*** SCPPA, on behalf of three project participants, including Burbank, signed a long-term power purchase agreement with Pebble Springs Wind Project LLC for the purchase of the generating capacity of 98.7 MW (total capacity) wind project, comprised of 47 Suzlon 2.1 MW wind turbines. The facility is located in Oregon. Burbank has a 10.132% (approximately 10 MW) entitlement interest in the total capacity, energy and environmental attribute rights produced by the facility. The agreement expires on January 31, 2027.

***Ameresco Chiquita Canyon Landfill Gas Project.*** Burbank entered into a power sales agreement with SCPPA for 16.7% (approximately 1.33 MW) of the output of Ameresco Chiquita Canyon Landfill Gas Project. The facility is developed, owned and operated by Ameresco Chiquita Energy, LLC in Chiquita Canyon Landfill in Valencia, California, near Highway 126 and west of Santa Clarita with a total capacity of 9.2 MW (gross), 7.8 MW (net). Burbank has an entitlement interest of 16.7% of the total capacity, energy and environmental attribute rights produced by the facility for 20 years. The plant began commercial operation on November 23, 2010. On February 22, 2024, SCPPA received a notice of force majeure due to a subsurface chemical reaction changing the hydrogen sulfide to dimethyl sulfide where the plant is not designed to treat or able to remove the substance, rendering it unable to operate in compliance with its air permit. The dimethyl sulfide overwhelms the gas treatment capacity of the plant. On October 16, 2024, SCPPA rejected the notice of force majeure and required that the plant owner make necessary upgrades to restore the plant to its historic quality and quantity.

***Copper Mountain Solar 3 Project.*** SCPPA, on behalf of Burbank and LADWP, entered into a power purchase agreement for 250 MW of generating capacity of the Copper Mountain Solar 3 Project, located on the desert plains near Boulder City, Nevada. This energy is transferred to the Marketplace Switchyard, where the Mead-Adelanto transmission line runs to California. The commercial operation date for the project was declared on April 8, 2015. The agreement expires on April 9, 2035. Burbank has a 16.0% (approximately 40 MW) entitlement interest in the total capacity, energy and environmental attribute rights produced by the facility.

(Burbank 2025 R. 15c2-12)

**Don A. Campbell I Geothermal Project.** SCPPA, on behalf of Burbank and LADWP, entered into a power purchase agreement for 16 MW of net generating capacity of the Don A. Campbell I Geothermal Project located in Nevada. The commercial operation date for the project was declared on December 19, 2014. The agreement expires on January 1, 2034. Burbank has a 15.38% (approximately 3.845 MW) entitlement interest in the total capacity, energy and environmental attribute rights produced by the facility.

**Valley Pumping Plant.** In 2002, Burbank installed a small micro-hydro system to take advantage of a required pressure reduction where Burbank's water facilities interface with The Metropolitan Water District of Southern California ("MWD") at the Valley Pumping Plant. Peak output of the facility is approximately 550 kilowatts ("kW"). The micro-hydro system generates power when BWP purchases water from MWD.

**Burbank Landfill Microturbines.** The Burbank Landfill produces landfill gas ("LFG") that is collected to generate renewable power. Ten Capstone microturbines (of 30 kW capacity each) installed at the site in 2001 and one Ingersoll-Rand microturbine (of 250 kW capacity) installed in 2006 reached their end-of-life in 2014. The site was then repowered in 2020 using microturbines with 800 kW of new generating capacity. The LFG is reliable and sufficient to support 800 kW of power generating capacity. The equipment installed includes necessary gas pretreatment system that will effectively remove undesirable constituents such as moisture, volatile organics, hydrogen sulfide, and siloxanes from the LFG before it is combusted in the power generating equipment. The modernized control system also allows for remote monitoring and control of the operation.

**Solar.** Burbank has distributed generation in the form of behind the meter customer-owned rooftop solar photovoltaic (PV) systems throughout Burbank. As of June 2025, there were 2,030 residential and commercial owned solar PV systems in Burbank totaling more than 18 MW of capacity. Burbank expects that by 2026, there will be between 20 and 22 MW of cumulative capacity installed in Burbank with approximately 34,000 to 38,000 MWh of solar generation from customers annually.

**Exchange Agreement.** On August 3, 2016, Burbank and Morgan Stanley entered into an energy exchange agreement from April 1, 2017 to March 31, 2022. Under the agreement, Burbank will receive 23,500 PCC 1 qualified renewable energy and associated Renewable Energy Credits ("RECs") per year, 23,500 MWh of firm energy and PCC 2 qualified RECs per year, and 9,500 PCC 3 RECs per year. In exchange, Burbank will be obligated to deliver to Morgan Stanley approximately 131,400 MWh annually of firm energy at a rate of 15 MW per hour. On July 8, 2021, the City and Morgan Stanley entered into another energy exchange agreement from April 1, 2022 to June 30, 2025 for the same terms.

**Desert Harvest II Solar Project.** In December 2017, Burbank, along with the Cities of Anaheim and Vernon, entered into a power sales agreement with SCPPA for Desert Harvest Project. The Desert Harvest Project is located in Riverside County, California and began commercial operations in December 2020. Desert Harvest II Solar Project supplies energy and renewable attributes to SCPPA under a twenty-five-year REC + Index structure contract. The City contracted to purchase approximately 31.34% of its output.

**Powerex Renewable Energy.** In September 2022, Burbank and Powerex Corp. entered into a purchase agreement for 220,000 MWh bundled renewable energy with energy generated by projects and all associated green and environmental attributes. Under the agreement, Burbank will receive 20,000 MWh PCC 1 qualified renewable energy and associated RECs per calendar year. The contract will be effective from October 1, 2022 to September 30, 2032.

**Tule Small Hydroelectric Project.** Burbank and Tule Hydro LLC entered into a 15-year power purchase agreement for 6.4 MW of installed generating capacity located in Tulare County, California. The

project's commercial operation date was February 2025. The project is expected to deliver approximately 330,000 MWh of energy and PCC 1 RECs over the course of the contract.

**Renewables 10-Year PCC 3.** Burbank entered into two 10-year agreements to purchase PCC 3 from 3 Degrees Group, Inc. The contracts will deliver 70,000 PCC 3 RECs per annual for a total of 700,000 RECs and a total cost of \$6.6 million. The PCC 3 certificates will contribute to the 60% RPS long term requirement and interim compliance period targets. The long-term requirement of the RPS regulation also requires 65% of all renewable contracts be at least 10 years or long in duration.

**Battery Storage.** In May 2024, Burbank commissioned its first long-duration energy storage (LDES) system, a 75 kW / 500 kWh ESS Energy Warehouse iron flow battery on Burbank 's EcoCampus. This system, integrated with a 265-kW solar array, will provide enough renewable power for 300 homes annually.

## **Fuel Supply**

Fuel procurement for BWP's local generation units and the City's participation in the SCPPA Magnolia Power Project is addressed as part of its overall energy hedging strategy and undertaken in accordance with the BWP Energy Risk Management Policy. Fuel procurement instruments used include over the counter physical contracts, over the counter financial swap contracts, options, the SCPPA Natural Gas Reserves Project and the SCPPA Prepaid Natural Gas Project (described below), and biomethane contracts. Energy hedging decisions are continuously monitored and reviewed at the Risk Oversight Committee. See "Electric System Initiatives – Wholesale Margins" below for additional information about the Risk Oversight Committee. In August 2023, the California Public Utilities Commission (the "CPUC") approved an increase in the allowable storage at the Aliso Canyon facility. Prior to that decision, the use of Aliso Canyon Storage had been limited and protocols were in place that allowed for gas withdrawal to meet demand and ensure reliability of the electricity and natural gas systems. After the CPUC August 2023 approval to increase the allowable storage at the facility, the use of Aliso Canyon by Southern California Gas Company has been less restrictive and has helped to reduce volatility of spot natural gas prices. Thus far, there has been no adverse impact to the City relating to Aliso Canyon operations.

**Natural Gas Reserves Project.** Burbank is a participant in SCPPA's Natural Gas Reserves Project. The Natural Gas Reserves Project includes SCPPA's leasehold interests in (i) certain natural gas resources, reserves, fields, wells and related facilities located near Pinedale, Wyoming and (ii) certain natural gas resources, reserves, fields, wells and related facilities in (or near) the Barnett Shale geological formation in Texas. Burbank has an interest in a portion of the production capacity of SCPPA's leasehold interests in the Natural Gas Reserves Project through a gas sales agreement with SCPPA, which agreement obligates Burbank to pay for its share of capital costs and costs related to operation and maintenance of the Natural Gas Reserves Project on a "take-or-pay" basis, as well as 100% of the debt service (on a several basis) on bonds issued by SCPPA to finance Burbank's share of the costs of development and acquisition of the Natural Gas Reserves Project.

**Prepaid Natural Gas Project.** Burbank 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, Burbank has entered into a natural gas supply agreement with SCPPA pursuant to which Burbank 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 the arrangement (as subsequently restructured) of approximately 27 years beginning on July 1, 2008.

## Transmission Resources

***Southern Transmission Project.*** The Southern Transmission System is owned by IPA and is one of the major components of IPP. Burbank is a participant in SCPPA's Southern Transmission Project, which provides Burbank with a 4.498% (currently 108 MW) entitlement in the transfer capability of the STS. Among other things, the STS provides for the transmission of energy from the IPP Generating Station to the California transmission grid. See "Power Supply-General – Non-Burbank Owned Resources – *Intermountain Power Project*" above. Burbank has a transmission service contract with SCPPA which obligates Burbank to pay its share of debt service on bonds issued by SCPPA for the project on a "take-or-pay" basis, as well as capital costs and costs related to operation and maintenance. 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.

***Southern Transmission Renewal Project.*** As part of the IPP Repowering Project (see "– Non-Burbank Owned Resources – *Intermountain Power Project*"), SCPPA is financing the costs of acquisition and construction of additional capital improvements to the Southern Transmission System (the "STS Renewal Project"), which initially will include new converter stations and AC switchyard expansions at the Adelanto Converter Station and the Intermountain Converter Station, and reactive power equipment. The total cost of the STS Renewal Project is estimated to be \$2.5 billion, and the City's share of such cost is 4.22%. The City has entered into a renewal transmission service contract related to the STS Renewal Project. Under such an existing agreement with IPP and such renewal transmission service contract the City is obligated to pay the cost of its share of the transfer capability on a "take-or-pay" basis, including principal of debt issued for the project, capital costs and costs related to operation and maintenance. See "– Indebtedness; Joint Powers Agency Obligations – *Joint Powers Agency Obligations.*"

The IPA Renewal Power Sales Contracts provided a process for IPP members to subscribe for shares of the new gas-fired or alternative repowering plant. The Burbank City Council approved BWP's recommendation for continued participation in the IPP project which enabled the City to retain its share of the project. The City's share under the IPA Renewal Power Sales Contract is 4.222%, or 101.33 MW.

***Mead-Phoenix Transmission Project, Authority Interest (Multiple Members).*** Burbank is a participant in SCPPA's member-related interest in the Mead-Phoenix Transmission Project, a 256 mile, 500-kV AC transmission line that extends between a southern terminus at the existing Westwing Substation (in the vicinity of Phoenix, Arizona) and a northern terminus at Marketplace Substation, a substation located approximately 17 miles southwest of Boulder City, Nevada. Burbank has entered into a transmission service contract with SCPPA under which SCPPA has sold to Burbank, on a "take-or-pay" basis, its entitlement share of 15.4% (approximately 35 MW) of the Authority's member-related ownership interest in the Mead-Phoenix Transmission Project and which obligates Burbank to pay its share of capital costs and costs related to operation and maintenance.

***Mead-Adelanto Transmission Project, Authority Interest (Multiple Members).*** In connection with the Mead-Phoenix Transmission Project, Burbank has an 11.5337% (approximately 101 MW) entitlement to SCPPA's member-related interest in the Mead-Adelanto Transmission Project, an approximately 202-mile, 500-kV AC transmission line that extends between a southwest terminus at the existing Adelanto Substation in southern California and a northeast terminus at Marketplace Substation, a substation located approximately 17 miles southwest of Boulder City, Nevada. Burbank has entered into a transmission service contract with SCPPA, under which SCPPA has sold to Burbank, on a "take-or-pay" basis, its entitlement of SCPPA's member-related ownership interest in the Mead-Adelanto Transmission Project. Burbank's transmission service contract with SCPPA obligates Burbank to pay its share of capital costs and costs related to operation and maintenance.

***Pacific Northwest-Pacific Southwest 500 kV DC Transmission Line.*** The DC Intertie is an 850 mile ± 500 kV DC line rated 3,100 MW connecting the Pacific Northwest with the Los Angeles Basin. The line is operated by both LADWP and Bonneville Power Administration (“BPA”). LADWP operates the southern section and BPA operates the northern section. Burbank and the cities of Glendale and Pasadena participated in the Sylmar Expansion Project which was completed in 1991 and which provided a 1,100 MW expansion (from 2,000 MW to 3,100 MW) of the DC Intertie’s AC/DC terminal converter station located at Sylmar, California. Burbank has ownership in 119 MW of capacity at the Nevada-Oregon border. Burbank currently has excess capacity on this line.

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## Customers and Energy Sales

The following table sets forth the electric revenues derived by Burbank from sales by classification of services and peak demand during the five fiscal years shown.

<b>Burbank Water and Power</b>					
<b>Electric Revenues and Peak Demand</b>					
<b>(\$000's)</b>					
<b>Fiscal Year Ended June 30,</b>					
	<b>2021</b>	<b>2022</b>	<b>2023</b>	<b>2024</b>	<b>2025 (Unaudited)</b>
Electric Revenues from Sales:					
Residential	\$45,553	\$43,974	\$48,931	\$49,794	\$59,217
Commercial <sup>(1)</sup>	39,435	42,876	46,242	48,736	52,872
Large Commercial <sup>(1)</sup>	58,345	60,875	66,082	67,060	69,047
Other Retail Revenues	6,513	6,578	4,161	7,861	10,855
Total Retail Revenues	<u>\$149,846</u>	<u>\$154,304</u>	<u>\$165,417</u>	<u>\$173,453</u>	<u>\$191,991</u>
Wholesale	42,088 <sup>(2)</sup>	21,486	40,324 <sup>(2)</sup>	23,197 <sup>(2)</sup>	22,452 <sup>(2)</sup>
Other Operating Revenues <sup>(3)</sup>	<u>9,040</u>	<u>6,600</u>	<u>7,146</u>	<u>6,962</u>	<u>16,035</u>
Total Revenues <sup>(4)</sup>	<u>\$200,974</u>	<u>\$182,390</u>	<u>\$212,887</u>	<u>\$203,612</u>	<u>\$230,478</u>
Peak Demand (MW)	292	246	290	263	309

<sup>(1)</sup> Declines in Fiscal Year ended June 30, 2021 are due primarily to the effects of the COVID-19 pandemic.

<sup>(2)</sup> Increase in Wholesale in Fiscal Year ended June 30, 2021 is due to higher demand during extreme weather events during the year. Increase in Wholesale in Fiscal Year ended June 30, 2023 is due to higher demand during extreme weather events and the resale of excess gas during the year. Decrease in Wholesale in Fiscal Year ended June 30, 2024, and Fiscal Year ended June 30, 2025, is due to less extreme weather events and the mild summer during the year. Wholesale uses excess assets to move energy outside of Burbank's retail system.

<sup>(3)</sup> Other operating revenues include transmission, telecommunications, intergovernmental, and other miscellaneous revenues. Other operating revenues do not include aid-in-construction.

<sup>(4)</sup> Totals may not add due to rounding.

Source: BWP.

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The following tables set forth the average number of retail customers and total retail energy sold during the past five fiscal years.

**Burbank Water and Power  
Average Number of Retail Customers**

	Fiscal Year Ended June 30,				
	2021	2022	2023	2024	2025
Residential	46,152	46,290	46,688	46,155	46,658
Commercial	6,861	6,880	6,959	6,914	6,890
Large Commercial	84	82	82	84	80
Total	53,097	53,252	53,729	53,153	53,628

Source: BWP.

**Burbank Water and Power  
Total Retail Energy Sold  
(Millions of kWh)**

	Fiscal Year Ended June 30,				
	2021	2022	2023	2024	2025
Residential	287	275	286	259	275
Commercial	448	476	475	461	475
Large Commercial	227	228	232	223	211
Total	962	979	993	943	961

Source: BWP.

**Largest Electric Customers**

Burbank’s five largest retail electric customers (excluding other City departments) accounted for approximately 17.04% of Burbank’s energy sales for the Fiscal Year ended June 30, 2025. Burbank’s ten largest retail electric customers (excluding other City departments), comprised of large commercial customers, accounted for approximately 22.26% of Burbank’s energy sales for the Fiscal Year ended June 30, 2025, and Burbank’s 25 largest retail electric customers (excluding other City departments), comprised of large commercial customers, accounted for approximately 31.38% of Burbank’s energy sales for the Fiscal Year ended June 30, 2025.

**Electric Rates and Charges**

Per Burbank Municipal Code, the utility must remain self-supporting from a financial standpoint and requires rates sufficient to maintain its financial health. Because costs can change suddenly and materially, a regular review and report on rates is necessary. BWP regularly evaluates such information needed to maintain adequate rates and uses such information in its assessment of its rates. Electric rates are established by the Burbank City Council and are not subject to regulation by the CPUC or by any other state agency.

Although its rates are not subject to approval by any federal agency, Burbank is subject to certain provisions of the federal Public Utility Regulatory Policies Act of 1978 (“PURPA”). PURPA requires state regulatory authorities and nonregulated electric utilities, including Burbank, to consider certain rate-making standards and to make certain determinations in connection therewith. Burbank believes that it is operating in compliance with PURPA.

(Burbank 2025 R. 15c2-12)

The Electric System’s base rates have been changed ten times over the period beginning July 1, 2013. Burbank provides no free electric services. A 1.5% increase originally scheduled to take effect in July 2020 was postponed due to the COVID-19 pandemic. In May 2021, the Burbank City Council approved a 2.5% rate increase, spread out over two increases of 1.24% each effective October 1, 2021 and April 1, 2022. The rate increases were phased in to allow economic recovery from the COVID-19 pandemic for the community. In May 2022, the Burbank City Council approved a total overall increase of 6.0%, effective July 1, 2022. In June 2023, the Burbank City Council approved a total overall increase of 8.5%, which was effective July 1, 2023, and an overall rate increase of 8.0%, effective July 1, 2024. In May 2025, the Burbank City Council approved a total overall increase of 9.9%, effective January 1, 2026, and an overall rate increase of 9.9%, effective January 1, 2027.

**Burbank Water and Power  
Percentage Change in Electric Rates<sup>(1)</sup>**

Effective Date	Overall System
07/01/13	1.75%
07/01/14	2.90
07/01/15	2.10
07/01/16	2.10
07/01/19	1.00
10/01/21	1.24
04/01/22	1.24
07/01/22 <sup>(2)</sup>	6.00
07/01/23 <sup>(2)</sup>	8.50
07/01/24	8.00
01/01/26	9.90
01/01/27	9.90

<sup>(1)</sup> Percentage change is based upon the immediately preceding rate.

<sup>(2)</sup> The increases effective July 1, 2022 and July 1, 2023 were higher than previous increases due to higher energy prices, investments in future sustainability, higher operating and maintenance expenses driven by inflation and supply chain issues.

Source: BWP.

The table below sets forth the weighted average billing price per kWh of Burbank’s various retail customer classes for the five fiscal years shown.

**Burbank Water and Power  
Weighted Average Retail Billing Price<sup>(1)</sup>  
(Cents per kWh)**

	Fiscal Year Ended June 30,				
	2021	2022	2023	2024	2025
Residential	15.86	16.01	17.12	19.25	21.50
Commercial	16.02	16.21	17.30	18.51	19.83
Large Commercial	13.96	14.08	15.05	16.02	16.53
Weighted Average – All Classes Combined	15.49	15.66	16.72	18.12	19.58

<sup>(1)</sup> All weighted average rates exclude annual in-lieu transfers to the City’s General Fund and street lighting transfers. City voters passed Measure T in June 2018 to continue a direct transfer of not more than 7% of BWP’s gross annual sales of electricity to pay for City’s essential services. See “– Transfers to the City’s General Fund.”

Source: BWP.

(Burbank 2025 R. 15c2-12)

## **Transfers to Burbank's General Fund**

In accordance with the City Charter, the Burbank City Council has a long-standing practice of authorizing annual transfers from the Electric Enterprise Fund to the City's General Fund in the form of an in-lieu transfer of 5.0% and a street lighting transfer of 1.5% of the City's gross sales of electricity (exclusive of wholesale sales to other public or privately-owned utilities). The practice of transfer from the Electric Enterprise Fund to the General Fund was challenged by a plaintiff in a complaint filed in June 2016, *Christopher Matthew Spencer v. the City of Burbank* (Case Number: BS162779). In June 2018, the voters of Burbank passed Measure T, a ballot measure that amended the City of Burbank Charter to continue this practice of annual transfers from BWP's gross annual sales of electricity, paid by retail electric ratepayers. On October 30, 2018, the plaintiff and the City entered into a settlement agreement in connection with their dispute over these transfers. The City receives a 7% In-lieu of Taxes on electric retail revenues that is not reflected in the Electric Fund's financial statements. This amount for the year ended June 30, 2025 is Electric in-lieu of \$10,378,720 and Street Lighting transfer of \$2,830,497.

## **Historical Net Revenues and Statement of Net Position of the Electric System**

The following two tables set forth (i) summaries of net revenues of the Electric System for the five fiscal years shown together with debt service coverage ratios with respect to BWP's Electric System revenue bonds and (ii) the statement of net position of BWP's Electric System for the five fiscal years shown.

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**Burbank Water and Power**  
**Historical Net Revenues and Debt Service Coverage**  
**Electric System**  
**(\$000's)**

**Fiscal Year Ended June 30,**

	<b>2021</b>	<b>2022</b>	<b>2023</b>	<b>2024</b>	<b>2025 (Unaudited)</b>
Operating revenue:					
Retail	\$149,846	\$154,304	\$165,417	\$173,453	\$191,991
Wholesale <sup>(1)</sup>	42,088	21,486	40,324	23,197	22,452
Other Operating Revenues <sup>(2)</sup>	<u>9,040</u>	<u>6,600</u>	<u>7,146</u>	<u>6,962</u>	<u>16,035</u>
Total Operating Revenue	\$200,974	\$182,390	\$212,887	\$203,612	\$230,478
Operating expenses:					
Retail (Fuel, Purchased Power and Power Operations) <sup>(3)</sup>	\$93,250	\$108,323	\$119,701	\$101,742	\$123,879
Wholesale <sup>(1)</sup>	34,197	18,845	37,386	20,975	20,942
Other (Distribution and Other O&M) <sup>(4)</sup>	47,147	35,617	49,265	52,212	58,262
Optional advanced pension payment <sup>(5)</sup>	<u>2,750</u>	<u>2,750</u>	<u>2,750</u>	<u>1,030</u>	<u>2,062</u>
Total Operating Expenses <sup>(6)</sup>	\$177,344	\$165,535	\$209,102	\$175,959	\$205,145
Operating income/(loss)	\$23,630	\$16,855	\$3,785	\$27,653	\$25,333
Other non-operating income <sup>(7)</sup>	<u>2,375</u>	<u>2,508</u>	<u>4,201</u>	<u>1,841</u>	<u>3,238</u>
Net Income Available for Debt Service (a)	\$26,005	\$19,363	\$7,986	\$29,494	\$28,571
Net Debt Service (b) <sup>(8)</sup>	\$3,403	\$3,403	\$3,788	\$10,412	\$10,046
Rate Covenant Coverage (Prior to In-Lieu) (a) / (b)	7.64x	5.69x	2.11x	2.83x	2.84x
Revenues Available After Debt Service (a) – (b)	\$22,602	\$10,944	\$4,198	\$19,082	\$18,525

(1) The increase in Wholesale in Fiscal Year 2020-21 is due to higher demand during extreme weather events during the year. Wholesale uses excess assets to move energy outside of Burbank's retail system. See "– Electric System Initiatives – Wholesale Margins."

(2) Other operating revenues include transmission, telecommunications, intergovernmental income, and other miscellaneous revenues.

(3) The increase in Retail Operating Expenses in Fiscal Year 2021-22 is primarily due to higher energy prices, coal supply issues at Intermountain Power Project, and one-time repairs for the Lake generating unit. The increase in Fiscal Year 2022-23 is primarily due to higher energy and gas prices, and the continued coal supply issues at Intermountain Power Project.

(4) The decrease in Other (Distribution and Other O&M) Operating expenses in Fiscal Year 2021-22 is primarily due to higher than expected CalPERS investment returns.

(5) During the Fiscal Year 2020-21 audit, the amount of optional advanced payment to CalPERS to reduce the City's unfunded actuarial liability for Fiscal Year 2019-20 and Fiscal Year 2020-21 was reclassified from non-operating expense to operating expense.

(6) Operating expenses exclude depreciation, in lieu of taxes, and interest expense.

(7) Other non-operating income includes interest income and other non-operating revenues, less other non-operating expenses. Other non-operating income does not include capital contributions, Build America Bonds subsidy, and non-cash adjustments to record market value adjustment for investment per Governmental Accounting Standards Board ("GASB") Statement No. 31 and market value adjustment for pension per GASB 68.

(8) Represents net debt service on outstanding bonds. Debt service on the Electric Revenue Bonds, Series of 2010B (Build America Bonds) (the "2010B Refunded Bonds") is net of the federal subsidy on the 2010B Refunded Bonds. Annual debt service beginning in Fiscal Year 2020-21 was much lower due to early redemption of the Electric Revenue Bonds, Series of 2010A. In March 2023, the Electric System issued \$120 million of fixed rate tax-exempt bonds to fund capital expenditures. The 2010B Refunded Bonds were redeemed in full with proceeds of the Electric Revenue Refunding Bonds, Series of 2024 on June 18, 2024.

Source: BWP.

**Burbank Water and Power**  
**Statement of Net Position**  
(\$000's)

	Fiscal Year Ended June 30,				
	2021	2022	2023	2024	2025 (Unaudited)
<b>ASSETS</b>					
Current and regulatory assets:					
Cash and cash equivalents .....	\$85,228	\$80,996	\$180,142	\$181,816	\$182,294
Accounts receivable, net.....	21,974	16,875	26,276	20,442	20,169
Inventories .....	8,747	8,813	9,752	14,522	19,914
Derivative instruments.....	-	2,020	1,417	3,729	1,162
Deposits and prepaid expenses .....	17,104	16,164	17,493	17,402	18,224
Interest receivable.....	159	285	191	246	545
Leases Receivable.....	-	302	310	319	327
Due from the City of Burbank .....	-	284	299	310	276
Regulatory costs to be recovered in one year	14	-	-	-	-
Restricted nonpooled investments .....	-	-	-	-	-
Total current and regulatory assets <sup>(1)</sup> .....	<u>133,226</u>	<u>125,739</u>	<u>235,880</u>	<u>238,786</u>	<u>242,911</u>
Noncurrent and regulatory assets:					
Interfund receivable .....	6,450	-	-	-	-
Regulatory costs for future recovery.....	-	-	-	-	-
Leases receivables.....	-	4,557	4,247	3,929	3,601
OPEB assets <sup>(1)</sup> .....	-	2,450	2,007	2,814	3,413
Total noncurrent and regulatory assets	<u>6,450</u>	<u>7,007</u>	<u>6,254</u>	<u>6,743</u>	<u>7,014</u>
Capital assets:					
Land.....	2,734	2,734	2,734	2,734	2,734
Rights to purchase power.....	1,335	1,335	1,335	1,335	1,335
Utility plant and equipment .....	619,709	561,708	588,686	601,876	646,614
Machinery and Equipment.....	-	78,957	80,175	88,417	91,073
Leased Assets .....	-	1,779	1,779	1,151	1,309
Subscription Assets.....	-	-	1,718	2,529	1,886
Construction in progress .....	29,527	36,323	44,368	54,972	66,130
Total utility plant and equipment.....	<u>653,305</u>	<u>682,836</u>	<u>720,796</u>	<u>753,014</u>	<u>811,081</u>
Less accumulated depreciation .....	<u>(339,915)</u>	<u>(361,212)</u>	<u>(381,583)</u>	<u>(394,814)</u>	<u>(416,615)</u>
Net utility plant and equipment .....	<u>313,390</u>	<u>321,624</u>	<u>339,213</u>	<u>358,200</u>	<u>394,466</u>
Deferred outflows of resources:					
Deferred amounts from loss on bond refunding.....	-	-	-	-	2,588
Deferred amounts from pensions.....	14,001	10,925	33,119	29,789	17,908
Deferred amounts from OPEB.....	1,214	1,660	4,510	3,604	2,058
Total deferred from pensions and OPEB	<u>15,215</u>	<u>12,585</u>	<u>37,629</u>	<u>33,393</u>	<u>22,554</u>
Total assets & deferred outflows of resources .....	<u>\$468,282</u>	<u>\$466,954</u>	<u>\$618,975</u>	<u>\$637,122</u>	<u>\$666,945</u>
<b>LIABILITIES AND FUND EQUITY</b>					
Current liabilities:					
Accounts payable and accrued expenses .....	\$13,059	\$12,630	\$13,820	\$12,256	\$15,563
Bond interest payable .....	279	275	775	763	684
Lease liability .....	-	245	247	215	264
Subscription payable.....	-	-	477	786	454
Interfund payable.....	12	-	-	-	-
Customer deposits.....	8,535	16,427	20,869	30,780	57,023
Deferred revenue .....	-	548	47	46	-
Current portion of revenue bonds payable, net.....	1,145	-	2,210	2,295	4,140
Current portion of compensated absences .....	<u>305</u>	<u>328</u>	<u>306</u>	<u>340</u>	<u>536</u>
Total current liabilities.....	<u>23,335</u>	<u>30,453</u>	<u>38,751</u>	<u>47,481</u>	<u>78,664</u>
Noncurrent liabilities:					
Revenue bonds payable <sup>(1)</sup> .....	52,497	52,499	181,444	178,568	175,635
Compensated absences .....	6,922	6,688	7,207	8,054	8,314
Regulatory credits.....	327	302	208	1,106	836
Subscription payable.....	-	-	768	708	254
Lease liability .....	-	1,127	891	301	195
Net OPEB liability.....	<u>3,766</u>	<u>-</u>	<u>5,098</u>	<u>2,730</u>	<u>1,808</u>

(Burbank 2025 R. 15c2-12)

Net pension liability <sup>(2)</sup> .....	<u>75,580</u>	<u>33,366</u>	<u>80,714</u>	<u>79,303</u>	<u>72,693</u>
Total non-current and regulatory liabilities .....	<u>139,092</u>	<u>93,982</u>	<u>276,331</u>	<u>270,770</u>	<u>259,735</u>
Deferred inflows of resources:					
Deferred amounts on pensions and OPEB	2,864	36,229	5,765	6,399	4,640
Deferred amount from leases	-	4,859	4,557	4,087	3,731
Derivative Instruments <sup>(3)</sup>	-	2,020	1,417	3,729	1,162
Total deferred inflows of resources	<u>2,864</u>	<u>43,108</u>	<u>11,739</u>	<u>14,215</u>	<u>9,533</u>
Total liabilities and deferred inflows of resources	<u>165,291</u>	<u>167,542</u>	<u>326,821</u>	<u>332,466</u>	<u>347,932</u>
Fund equity:					
Total net position.....	<u>302,991</u>	<u>299,412</u>	<u>292,154</u>	<u>304,656</u>	<u>319,013</u>
Total liabilities and net assets .....	<u>\$468,282</u>	<u>\$466,954</u>	<u>\$618,975</u>	<u>\$637,122</u>	<u>\$666,945</u>

<sup>(1)</sup> In Fiscal Year 2022-23, the City issued the Electric Revenue Bonds, Series of 2023 in the principal amount of \$120,000,000 for capital improvement.

<sup>(2)</sup> Net pension liability was lower in Fiscal Year 2021-22 due to significantly higher investment returns. Investment returns were lower in Fiscal Year 2022-23 causing net pension liability to increase.

<sup>(3)</sup> In Fiscal Year 2021-22, the City implemented GASB Statement No. 53, "Accounting and Financial Reporting for Derivative Instruments" recording the fair value of the financial natural gas hedges.

Source: BWP.

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## Capital Improvements

Burbank has a capital improvement program designed to meet load requirements, repair and replace facilities as needed, and satisfy new safety and regulatory requirements. All capital improvements are normally considered and adopted as part of Burbank’s annual budget process, although additional capital expenditures may be approved as needed. Burbank currently expects to finance such capital improvements through a combination of bond financing, governmental grants and a “pay-as-you-go” basis.

The following table is a summary of Burbank’s Five-Year Capital Improvement Program for the Electric System.

### Burbank Water and Power Five-Year Capital Improvement Program (\$000’s)

	2025-26 Adopted	2026-27 Forecast	2027-28 Forecast	2028-29 Forecast	2029-30 Forecast	Total Forecast
Power Supply Improvement Projects	\$9,525	\$2,775	\$16,125	\$950	\$21,175	\$50,550
Distribution Expansion Projects	20,344	6,042	11,059	16,138	7,569	61,152
Distribution Replacement Projects	32,668	28,308	28,246	18,338	19,085	126,645
New Customer Projects/AIC	56,285	7,050	11,242	15,178	10,750	100,505
Customer Service and others	6,906	2,213	4,469	3,092	1,925	18,605
Capital Outlay and other	7,992	7,098	11,945	11,046	8,943	47,024
Total CIP	<u>\$133,720</u>	<u>\$53,486</u>	<u>\$83,086</u>	<u>\$64,742</u>	<u>\$69,447</u>	<u>\$404,481</u>

Source: BWP.

## Indebtedness; Joint Powers Agency Obligations

**Electric System Revenue Bonds.** As of December 31, 2025, Burbank has \$164,055,000 in outstanding principal amount of long-term obligations payable from net revenues of the Electric System (after the payment of operating and maintenance expenses of the Electric System) consisting of \$44,055,000 in outstanding principal of Electric Revenue Bonds, Series of 2024 Refunding bonds and \$120,000,000 in outstanding principal of Electric Revenue Bonds, Series of 2023.

**Joint Powers Agency Obligations.** As described herein, Burbank contracts with IPA and SCPPA. Obligations of Burbank under the agreements with IPA and SCPPA constitute operating and maintenance expenses of the Electric System payable prior to any of the payments required to be made on Burbank’s Electric System revenue bonds. Agreements between Burbank and IPA and Burbank and SCPPA (other than the agreement relating to SCPPA’s Prepaid Natural Gas Project bonds) are on a “take-or-pay” basis, which requires payments to be made whether or not applicable projects are operating or operable, or whether the output from such projects is suspended, interfered with, reduced, curtailed or terminated in whole or in part. In addition, all of these agreements (other than the agreements relating to SCPPA’s Prepaid Natural Gas Project bonds and the Natural Gas Reserves Project bonds) contain “step up” provisions obligating Burbank to pay its relevant share following a failure to pay by a defaulting participant. Burbank’s participation and share of principal obligations (without giving effect to interest due on the obligations or any “step up” provisions) for each of the joint powers agency projects in which it participates are shown in the following table.

**Outstanding Debt of Joint Powers Agencies and Burbank’s Share  
(as of December 1, 2025)**

	<u>Principal Amount of Outstanding Debt</u>	<u>City’s Participation<sup>(1)</sup></u>	<u>City’s Share of Principal Amount of Outstanding Debt<sup>(2)</sup></u>
<b>Intermountain Power Agency</b>			
Intermountain Power Project (IPP) <sup>(3)</sup>	\$112,520,000	4.021%	\$4,524,429
IPP Renewal Project	1,695,130,000	3.334	56,515,634
<b>Southern California Public Power Authority</b>			
STS Project	72,190,000	4.498	3,247,106
STS Renewal Project <sup>(4)</sup>	1,790,705,000	4.222	75,603,565
Magnolia Power Project <sup>(5)</sup>	187,770,000	32.350	60,744,346
Milford Wind Corridor Phase I	52,835,000	5.000	2,641,750
Prepaid Natural Gas Project <sup>(6)</sup>	219,555,000	33.000	72,453,150
Natural Gas Project	7,255,000	100.000	7,255,000
Tieton Hydropower Project	<u>26,585,000</u>	50.000	<u>13,292,500</u>
Total	\$4,164,545,000		\$296,277,481

(1) Obligation is subject to increase upon default of another project participant (other than with respect to SCPPA’s Prepaid Natural Gas Project bonds and the Natural Gas Project bonds).

(2) Excludes interest on the debt.

(3) Does include Burbank’s share of the IPP excess power sales agreement.

(4) Until the effective date of the IPA Renewal Power Sales Contract, debt service will be based on the original transmission service contract. As a result, the City’s share of outstanding debt is currently 4.498%, and upon the effective date of the IPA Renewal Power Sales Contract will be 4.222%. See “– Non-Burbank Owned Resources – Intermountain Power Project” and “– Transmission Resources – Southern Transmission Renewal Project.” Subsequent to March 31, 2024, SCPPA issued \$562,855,000 principal amount of bonds for the STS Renewal Project, of which the City’s share is \$21,901,633.

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

(6) The Prepaid Natural Gas Project is a “take-and-pay” contract. Payments by Burbank are contingent upon the delivery of gas. Source: BWP; IPA.

For the Fiscal Year ended June 30, 2025, Burbank’s payments of debt service on its joint powers agency obligations aggregated approximately \$11.3 million. 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.

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## Electric System Initiatives

**Competitiveness Transition Plan.** In 1998, the BWP Board and the Burbank City Council adopted, and has subsequently from time to time updated, its “Competitiveness Transition Plan” (as updated, the “Plan”) in response to the then anticipated impacts of deregulation in California. Burbank has never granted open access for Burbank customers.

These goals have been adopted to fulfill the Plan:

- Maintain competitive and stable rates for all customer classes;
- Optimize use of assets, manage costs, and increase reserves;
- Maintain sound financial policies to ensure BWP’s financial stability;
- Ensure that BWP is competitive with other Western utilities; and
- Uphold standards of customer service and reliability.

**Power Supply Resources.** The availability of local generation through existing facilities (the cost of which is more economic during periods of high cost in the power market) as well as the additional facilities utilizing state-of-the-art natural gas-fired technology (including the Lake 1 Unit and the Magnolia Power Project) are designed to allow Burbank to more efficiently dispatch local generation and to hedge against future market volatility in energy prices. In addition, utilizing local generation generally improves regional electric reliability because it does not depend on long-distance interstate transmission lines.

Burbank has taken the following actions to serve its customers and to mitigate the impact of recent changes in its power supply resource portfolio:

**Integrated Resource Plan (“IRP”).** The Burbank City Council approved the most recent IRP on December 5, 2023; the prior IRP was approved on December 11, 2018 and focused on decisions affecting coal-fired generation and the addition of cost-effective renewable energy in an environment of reduced load growth. The IRPs provide a long-term strategic framework for BWP’s power supply portfolio, incorporating statewide policies, regional market conditions, and community priorities. Both IRPs recognized the need to plan for continued reductions in greenhouse gas emissions and outlined the City’s strategy to meet Renewable Portfolio Standard (RPS) requirements.

**Forward Purchases and Energy Risk Management.** BWP has developed short-term as well as long-term energy procurement strategies to reduce price risks and volatility. These strategies are monitored by BWP management utilizing the Energy Risk Management Policy originally adopted in 2003 and last amended in 2022.

**Renewable Energy.** As described under “– Renewable Energy Resources” above, the Burbank City Council has adopted a RPS policy consistent with State law. For the Fiscal Year ended June 30, 2025, renewable energy resources made up approximately 52.9% of Burbank’s total retail sales. Burbank is on track to meet the Renewables Portfolio Standard of 46% for calendar year 2025. As Burbank expects that the cost of renewable energy, relative to other energy options, may be greater, the acquisition of additional renewable resources may result in increased costs to Burbank and may require future rate increases, which are subject to Burbank City Council review and approval.

**Wholesale Margins.** Wholesale margins for the Fiscal Year ended June 30, 2025 were \$1,510,000. Wholesale margins continue to contribute to Burbank’s financial performance by reducing the utility’s overall power supply costs. Wholesale trading opportunities exist because Burbank is able to market

BWP's excess capacity, energy or transmission. Burbank believes that wholesale transactions are low risk because they are short-term (e.g., mostly less than 30 days), and not open-ended transactions. The trading risks are also mitigated through the adoption of the Energy Risk Management Policy, the formation of the Risk Oversight Committee ("ROC") and oversight by the Financial Planning and Risk Manager. The ROC meets regularly to review counterparty credits and transactions. Voting members of the ROC include the General Manager, Chief Financial Officer, Assistant General Manager/Power Supply, Energy Control Center Manager, Power Production Manager, Power Resource Manager, and Financial Planning and Risk Manager.

**Financial Reserves.** BWP management initially developed a financial reserve policy to maintain its long-term rate stability in 2003. The policy was last updated in 2023. Financial reserves are established for general operating expenses, debt repayment and capital funding, fleet replacement and general plant replacement. Under the financial reserve policy, BWP's updated financial reserve is based on available cash to fund normal operation per day or days cash on hand. Days cash on hand is calculated by taking the unrestricted cash and investments less depreciation and dividing by the annual operating expenses for one day. The financial reserve policy includes a minimum reserve and a recommended reserve. The approved minimum financial reserve for the Electric System is 105 days cash on hand and a recommended range between 160 to 240. The Electric System had 176 days cash on hand on June 30, 2025.

**Customer Relations.** As a community owned utility, BWP's relationship with its customers and community stakeholders continues to be an important focus. As the utility moves towards more renewable energy, which is intermittent in nature and as customers continue to electrify their transportation and homes, BWP will educate, engage, and work with customers to adopt beneficial electrification and to manage and shape load.

In late 2020, BWP's marketing group began pursuing an omni-channel marketing strategy with an emphasis on digital and social media channels to broaden its reach. This has resulted in greater opportunities for engagement with both residential and commercial customers about key issues such as COVID-19 relief, water conservation, and new EV rebate programs. Seventy-six percent of customers in the latest residential survey rated outbound communications as highly satisfactory, and BWP recently won two national awards from the American Public Power Association ("APPA"). APPA recognized BWP in print/digital and web/social media categories with Awards of Excellence. Burbank has maintained an outstanding system-wide reliability statistic. For Fiscal Year 2024-25, the system average interruption was only 12.03 (SAIDI) minutes per customer. A low frequency of outages helped minimize the system average outage duration. The Burbank outage frequency rate was approximately 0.32 (SAIFI) outages per customer every year.

## **Employee Relations**

As of June 30, 2025, 273 full-time equivalent Burbank employees were assigned to the Electric System. Certain functions supporting the Electric System's operations, including but not limited to, meter reading, customer billing and collection, finance, administration, and operations technology are performed by BWP staff.

All BWP employees fall into one of four categories:

- (1) Those represented by Local No. 18 of the International Brotherhood of Electrical Workers ("IBEW");
- (2) Those represented by the Burbank City Employees' Association ("BCEA"), which is affiliated with the American Federation of State, County and Municipal Employees as Local No. 3143;

(Burbank 2025 R. 15c2-12)

- (3) Those represented by the Burbank Management Association (“BMA”); and
- (4) Those that are unrepresented.

The BCEA, BMA and IBEW labor contracts are current. The BCEA labor contract will expire on June 30, 2026. The BMA labor contract will expire on June 30, 2028, and the IBEW labor contract will expire on June 30, 2027. Work will continue under the terms of the existing labor contract during negotiations pursuant to each labor contract until a new contract is in place.

There have been no strikes or other material work stoppages by Burbank employees within the last fifteen years.

### **Pension Plan and Other Post-Employment Employee Benefits for Employees of the Electric System**

**Pension Plan.** Burbank’s defined benefit pension plan, the Public Employees Retirement System (“PERS”), provides retirement and disability benefits, annual cost-of-living adjustments and death benefits to plan members and their beneficiaries. PERS is part of the Public Agency portion of the California Public Employees Retirement System (“CalPERS”), an agent multiple-employer plan administered by CalPERS, which acts as a common investment and administrative agent for participating public employers within the State of California. A menu of benefit provisions, as well as other requirements, is established by state statutes within the Public Employees’ Retirement Law. Burbank selects optional benefit provisions from the benefit menu by contract with CalPERS and adopts those benefits through local ordinance. 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](http://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.*

Employees of the Electric System participate in Burbank’s CalPERS Miscellaneous Plan. Burbank active plan members in the CalPERS Miscellaneous Plan hired prior to January 1, 2013, are required to contribute 8.00% to 9.14% 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 retirement system are required to contribute 7.50% of their annual covered salary. All Public Employees’ Pension Reform Act members pay their full employee contribution. The City no longer pays for any employee contributions for any bargaining group.

Burbank is required to contribute the actuarially determined remaining amounts necessary to fund the benefits for its members. The actuarial methods and assumptions used are those adopted by the CalPERS Board of Administration. Burbank is required to contribute at an actuarially determined rate for the normal cost and a flat dollar amount for the required unfunded liability contribution. In Fiscal Year 2024-25, Burbank contributed 30.19% of annual covered payroll. The contribution requirements of plan members are established by state statute and the employer contribution rate is established and may be amended by CalPERS. The Electric System is allocated its portion of the required contributions. Approximately 34.74% of Burbank’s CalPERS obligations are allocated to the Electric System. Burbank contributed 100% of the portion of the employer’s actuarially required contribution allocable to the Electric System from the Electric Utility Fund for the Fiscal Years ending June 30, 2023, June 30, 2024, and June 30, 2025, in the amounts of \$6,589,114, \$5,770,282, and \$6,613,596, respectively. Burbank has budgeted to contribute \$7,909,688 as the Electric System’s allocable share of the required contribution for Fiscal Years 2025-26. In addition to the annual required contribution, the Electric Utility Fund also made an additional voluntary lump sum payment of \$2,062,200 to CalPERS to reduce the City’s unfunded actuarial liability during Fiscal Year 2024-25. This payment was the second year of a two-year citywide funding plan that began in Fiscal Year 2023-24 to reduce future pension obligations. Burbank’s Miscellaneous Plan had a funded ratio of 81.27% and 78.59% as of June 30, 2025, and 2024, respectively.

(Burbank 2025 R. 15c2-12)

In Fiscal Year 2014-15, Burbank implemented Governmental Accounting Standards Board (GASB) Statement No. 68, "Accounting and Financial Reporting for Pensions, an Amendment of GASB Statement No. 27" and GASB Statement No. 71, "Pension Transition for Contributions Made Subsequent to the Measurement Date, an Amendment of GASB Statement No. 68." These GASB Statements establish standards for measuring and recognizing liabilities, deferred outflows of resources, deferred inflows of resources, and expenses. For defined benefit pension plans, these GASB Statements identify the methods and assumptions that should be used to project benefit payments, discount projected benefit payments to their actuarial present value, and attribute that present value to periods of employee service. As of June 30, 2025, the proportionate share of Burbank's net pension liabilities allocable to the Electric System was reported to be \$72,693,000 (measured as of June 30, 2024, and based upon a June 30, 2023, actuarial valuation rolled forward to June 30, 2024, using standard update procedures), a decrease of \$6,610,000 over the prior fiscal year. The Electric System's proportionate share of the Net Pension Liabilities was 34.74% of the Net Pension Liabilities for Burbank's Miscellaneous Plan as a whole for Fiscal Year 2024-25. Reported deferred outflows of resources as of June 30, 2025 (to be recognized as a reduction of net pension liability in future periods) were \$17,907,799 with reported deferred inflows of resources (to be recognized as pension expense in future periods) of \$76. For the Fiscal Year ended June 30, 2025, Burbank's Miscellaneous Plan Net Pension Liability as a percentage of covered-employee payroll was 229.48%. The Miscellaneous Plan Net Pension Liability as a percentage of the Total Pension Liability for Burbank's Miscellaneous Plan was 81.27% for such Fiscal Year.

***Post-Retirement Health Care Plans.*** Burbank also administers certain post-employment health care benefits under Burbank Employees Retiree Medical Trust ("BERMT"), the Utility Retiree Medical Trust ("URMT"), and the CalPERS Public Employees' Medical and Hospital Care Act ("PEMHCA") plan. The Electric System also makes contributions for such other post-employment benefits ("OPEB"). The Electric System assumes its share of OPEB costs based upon the results of actuarial studies. The City has pre-funded the PEMHCA and URMT plans through CalPERS OPEB Trust ("CERBT") and has a policy of contributing 100% of the City's actuarially determined contribution each year.

BERMT is a single employer, defined benefit plan which was established in April 2003 by Burbank's employee associations to provide post-retirement medical benefits to all non-safety employees, including elected and appointed officials. The trust is controlled by seven voting members from the various employee associations appointed to three-year terms. Burbank appoints an eighth member to the board, but that member is non-voting. Represented plan members are required to contribute \$50 per bi-weekly pay period, which Burbank matches. Plan provisions and contribution requirements are established by and may be amended by the BERMT board. Investments are determined by the BERMT plan trustees and are governed by ERISA provisions. Eligibility for benefits requires that members are retired and have reached age 58 with a minimum of five years of contributions into the plan. The benefit provided ranges from \$150 to \$630 in reimbursements per month for eligible medical expenses. The Electric System has allocated its portion of the required contributions. For the Fiscal Year ended June 30, 2024, the allocable portion of Burbank's contributions to BERMT paid from the Electric Utility Fund totaled \$364,495. For the Fiscal Year ended June 30, 2025, the allocable portion of Burbank's contributions to BERMT paid from the Electric Utility Fund totaled \$371,950. The Electric Utility Fund has budgeted \$368,223 for its share of contributions to BERMT in Fiscal Year 2025-26.

The PEMHCA Plan was established with CalPERS as a single employer plan. Burbank pays the required PEMHCA minimum contribution for all miscellaneous and safety employees retiring directly from Burbank. The Fiscal Year 2024-25 PEMHCA minimum contribution was \$158.00 per month. In addition, Burbank paid \$100.00 per month for 13 management retirees and paid \$188.00 per month for nine IBEW retirees. For these management/IBEW retirees, the PEMHCA minimum required contribution of \$158.00 is paid in addition to the retiree health contribution amounts. The PEMHCA benefit provisions are established and amended through negotiations between Burbank and its employee associations. For the Fiscal Year ended June 30, 2025, Burbank's annual determined contribution was \$4,768,000 and the

(Burbank 2025 R. 15c2-12)

allocable portion of Burbank's contributions to the PEMHCA plan paid from Electric Utility Fund totaled \$939,296. As of June 30, 2025, the PEMHCA plan had a funded ratio of 84.66%.

Burbank also entered into an agreement on July 22, 2008, to provide certain OPEB to the IBEW employees, through the URMT, an agent multiple employer plan. The agreement is to supplement benefit payments from BERMT and PEMHCA for IBEW members and 12 management employees. The total target benefit is \$1,200/month for individuals age 50 to age 64 and \$750/month for those age 65 and above, with the exception that for qualifying employees who retire after December 16, 2015 and who have not contributed to Medicare while employed at Burbank and who are also not otherwise eligible for premium-free Medicare Part A at age 65 and older, the maximum amount at age 65 and older shall be \$975/month, including payments from BERMT, PEMHCA minimum and the URMT. For the Fiscal Year ended June 30, 2025, Burbank's annual determined contribution was \$39,000 and Burbank contributed \$48,000 for the URMT. As of June 30, 2025, the URMT had a funded ratio of 129.03%.

In Fiscal Year 2017-18, Burbank implemented GASB Statement No. 75, "Accounting and Financial Reporting for Postemployment Benefit Other Than Pension Plans." This Statement replaces the requirements of Statements No. 45, "Accounting and Financial Reporting by Employers for Postemployment Benefits Other Than Pensions", as amended, and No. 57, "OPEB Measurements by Agent Employers and Agent Multiple-Employer Plans", for OPEB. This Statement establishes standards for recognizing and measuring liabilities, deferred outflows of resources, deferred inflows of resources, and expenses. For defined benefit OPEB, this Statement identifies the methods and assumptions that are required to be used to project benefit payments, discount projected benefit payments to their actuarial present value, and attribute that present value to periods of employee service. Note disclosure and required supplementary information requirements about defined benefit OPEB are also addressed. As of June 30, 2025, the proportionate share of Burbank's net OPEB liabilities allocable to the Electric System was \$1,808.

## **Litigation**

At any given time, there are certain claims and disputes, including those currently in litigation, that arise in the normal course of Burbank's Electric System enterprise activities. In the view of BWP management, based on consultation with the City Attorney, there is no litigation, present or pending, which will, individually or in the aggregate, materially impair Burbank's ability to service its Electric System indebtedness or which will have a material adverse effect on the business operations of the Electric System.

## **Future Developments**

There has been increased development and service requests including large site developments, major housing developments, and accessory dwelling units during recent years and this trend is expected to continue in the years to come. In the last decade, BWP has energized about 400 new residential units. Based on the current proposed development, BWP is on the path to energize more than 2,000 new residential units in the next three to four years.

## **CITY OF GLENDALE**

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

### **General Description**

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

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

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

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

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

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

### **Management of Glendale Water and Power**

The Glendale City Council (the “City Council”) has established the Glendale Water and Power Commission (the “Commission”), which is an advisory commission with the power and duty to make recommendations to the City Council: concerning (i) the operations and facilities of Glendale Water and Power and the need for changes or additions in its plant or in its operation; (ii) ways and means of financing

changes and additions to the plant or the methods of operation; and (iii) changes of administrative policy which the commission deems desirable in order that Glendale Water and Power may better serve the people of Glendale. In addition, the Commission serves as an appellate board with respect to cases concerning energy and water meter tampering and water backflow prevention devices. The Commission may also exercise such other powers and duties as may be prescribed by ordinance not inconsistent with the City Charter.

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

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

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

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

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

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

**Glendale Water and Power Governance**

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

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

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

**Principal Existing Facilities; Resources Generally**

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

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

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

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

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

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

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

Glendale is also currently developing other programs related to electric demand and supply. In 2020, the City Council authorized a contract with Lime Energy Services Company (now Wildan Energy Co.) for a 36,500 MWh/8.32 MW commercial energy efficiency program. The program has delivered 28,000 MWh of savings (78% of program goal) and load reduction of 2.8 MW (35% of program goal) in

the first 3.5 years of the seven year program term. In November 2023, the City Council awarded two contracts for Phase 1 of the City Owned Solar Development Program. Motive Energy is currently conducting an environmental study for a ground mount solar project. Solar Optimum was awarded an Engineer, Procure, Construction contract for a rooftop or carport solar project on five sites. Total expected capacity for all six sites included in Phase 1 of the City Owned Solar Development Program is 4.9 MW. The GWP Perkins building roof top solar project was completed in March 2025 and the Central Library roof top solar project is scheduled for completion in December 2025. The Sports Complex and GWP's Utility Operations Center parking lot carpool solar projects are currently in the permitting process. The City continues to actively explore other local clean energy resources that can deliver energy, energy savings, storage and/or capacity to the City without utilizing GWP's transmission resources.

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

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

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

Source: Glendale Water and Power.

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## Power Supply

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

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

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

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

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

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

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

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

<sup>(1)</sup> During the twelve-month period ended June 30, 2025.

<sup>(2)</sup> Rated or name-plate capacities. As of June 2024, the Grayson Power Plant is under repowering; all units were demolished, except for Unit 9.

<sup>(3)</sup> Entitlements, firm allocations and contract amounts.

<sup>(4)</sup> Market purchases are spot-market purchases.

Source: Glendale Water and Power.

**Joint Powers Agency Resources/Remote Ownership Interests**

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

IPP coal operation was shut down on November 26, 2025.

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

*Original Entitlement* – Glendale contracted with IPA to purchase a 30 MW (1.704%) entitlement to the IPP plant. This contract obligates Glendale to pay its proportional share of the plant costs (including debt service and other fixed expenses), regardless of the amount of energy, if any, scheduled to Glendale, for the life of the facility.

*Excess Power Sales Contract* – Glendale, the cities of Burbank and Pasadena, and LADWP (the “California Purchasers”) contracted with 27 sellers (the “Utah Participants”) and IPA (acting as agent for the sellers) to purchase a 379 MW (21.06%) entitlement of the IPP plant, which was deemed in excess of the sellers’ needs. The California Purchasers agreed to divide the excess

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

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

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

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

Prior to the enactment of Utah H.B. 3004, IPA stated that Utah S.B. 161 would create obligations for IPA that are inconsistent with IPA's obligations under federal regulations and the IPP construction and operating permits issued under federal law; and that if IPA complied with Utah S.B. 161, as originally enacted, IPA may be subject to enforcement actions that could result in IPA being required to cease operation of the IPP coal units prior to the scheduled commercial operation date of the IPP repowering project and that may interfere with the construction and operation of the IPP repowering project. In public testimony with respect to Utah H.B. 3004, IPA management stated that the new bill made some important adjustments to the legislation. IPA has indicated that it is still working to determine the impact of Utah S.B. 161, as modified by Utah H.B. 3004, and to identify the appropriate course of action in response to the recent enactments. The City cannot predict the impacts of the new legislation on the operation of IPP or the construction and operation of the IPP repowering project.

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

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

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

## **Purchased Power**

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

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

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

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

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

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

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

## **Fuel Supply**

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

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

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

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

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

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

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

## Existing Transmission Resources

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

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

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

<sup>(1)</sup> Glendale has rights to approximately 33 MW between IPP and Mona Substation and 3 MW between IPP and Gonder Substation. These rights vary by season and direction.

Source: Glendale Water and Power.

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

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

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

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

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

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

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

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

***Mead-Adelanto Transmission Project, SCPPA Interest (Multiple Members).*** Glendale is entitled to 112 MW (7.5%) of transmission capacity from the Mead-Adelanto Transmission Project, an approximately 202-mile, 500-kV AC transmission line that extends between a southwest terminus at the existing Adelanto Substation in southern California and a northeast terminus at Marketplace Substation, a substation located approximately 17 miles southwest of Boulder City, Nevada. Glendale has entered into a transmission service contract with SCPPA, under which SCPPA has sold to Glendale, on a “take-or-pay”

basis, its entitlement share of SCPA's member-related ownership interest in the Mead-Adelanto Transmission Project. Glendale's transmission service contract with SCPA obligates Glendale to pay its share of debt service on bonds issued by SCPA for the project, as well as capital costs and costs related to operation and maintenance.

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

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

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

### **Wholesale Transactions**

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

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

### **Interconnections and Distribution Facilities**

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

## Electric Rates and Charges

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

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

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

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

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

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

Source: Glendale Water and Power.

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

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

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

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

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**GLENDALE WATER AND POWER  
PERCENTAGE INCREASE IN ELECTRIC RATES**

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

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

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

Source: Glendale Water and Power.

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## Customers, Energy Sales, Revenues and Demand

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

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

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

<sup>(1)</sup> Fluctuations in sales to other utilities revenues were due primarily to changing market demand.

Source: Glendale Water and Power.

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

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

## Capital Requirements

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

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

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

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

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

## Insurance

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

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

## Transfers to the General Fund

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

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

## Indebtedness; Joint Powers Agency Obligations

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

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

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

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

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

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

(1) Participation obligation is subject to increase upon default of another project participant (other than with respect to SCPPA’s Prepaid Natural Gas Project bonds).

(2) Does not include interest on the debt.

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

(4) LADWP has purchased from Glendale its 10.0% output entitlement share and has agreed to pay costs associated therewith.

(5) LADWP has purchased from Glendale its 7.630% output entitlement share and has agreed to pay costs associated therewith.

(6) LADWP has purchased from Glendale its 4.902% output entitlement share and has agreed to pay costs associated therewith.

Source: Glendale Water and Power; IPA.

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

**Contingent Obligations for Wind Energy Projects.** Glendale has entered into three power sales agreements with SCPPA, under which SCPPA has sold to Glendale on a “take-or-pay” basis, its entitlement

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

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

### **Historical Operating Results and Debt Service Coverage**

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

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

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

<sup>(1)</sup> Other revenues available for debt service include interest revenues plus other non-operating revenues less other non-operating expenses excluding interest expenses. Does not include contributions in aid.

<sup>(2)</sup> Operating expenses exclude depreciation, gas depletion, capital expenditures and transfers to Glendale's general fund (which transfers are payable after the payment of debt service).

<sup>(3)</sup> Includes generation, fuel, purchase power and labor expenses.

<sup>(4)</sup> Production costs for the Fiscal Year ended June 30, 2024 are lower than the two prior Fiscal Years due to (i) operation of a single unit of the Grayson Power Plant, as all units except for Unit 9 were taken offline as of June 30, 2023 in preparation for demolition; (ii) moderate weather during the summer months of 2023; and (iii) lower natural gas prices in the spot markets relative to prior Fiscal Years.

<sup>(5)</sup> Represents debt service on Glendale's outstanding Electric System revenue bonds.

<sup>(6)</sup> Increase in Debt Service Coverage for the Fiscal Year ended June 30, 2024 due to decrease in production costs, and increase in interest income and rates.

Source: Glendale Water and Power.

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

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

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

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

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

Source: Glendale Water and Power.

## Employees of Glendale Water and Power

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

## Wildfire Mitigation Measures

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

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

- The City responds to red flag wind warnings issued for the area by the National Weather Service by de-energizing (without loss of customer load) the transmission line of the Electric System that runs across uninhabited hilly terrain with elevated fire risk. In addition, GWP is looking into employing the broken conductor technology and fast acting protection scheme to mitigate the risk of fire furthermore.
- The City has installed fire resistant wrap/coating poles in high fire risk locations and has installed covered conductors (in selected Tier 2 areas).
- The City expanded vegetation management to exceed minimum clearance requirements by trimming trees down to the telecommunications level.
- The City installed devices to minimize the risk of fire in brush areas from ejecting a blown fuse.
- To evaluate the effectiveness of its wildfire plan, the City developed metrics posted on an internal website to track the number of electrical assets replaced in Tier 2 and Tier 3 areas.

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

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

## **Litigation**

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

## **Grayson Litigation**

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

In a related case that the Los Angeles Superior Court coordinated with the Sierra Club matter, on March 21, 2022, the Glendale Residents Against Environmental Destruction (“GRAED”) filed a Petition for Writ of Mandate against the City (*Glendale Residents Against Environmental Destruction v. City of Glendale, et al.*, Los Angeles Court Case No. 22STCP01021) also challenging the City Council’s February 15, 2022 certification of an FEIR for the proposed Grayson Repowering Project and authorizations to move forward with various Grayson Repowering Project development activities. On July 31, 2023, the trial court issued a statement of decision denying GRAED’s petition and entered a judgment denying the petition on August 28, 2023. GRAED filed a timely notice of appeal. The hearing

on GRAED's appeal was held on September 3, 2024 in the California Court of Appeal. On September 30, 2024, the Court of Appeal issued its decision denying GRAED's appeal and upholding the trial court's decision. GRAED did not file a request for further review and therefore the litigation has concluded in favor of the City.