WATER | ENERGY | LIFE

CITY OF RIVERSIDE

PUBLIC UTILITIES

2025

FINANCIAL REPORT

RIVERSIDE PUBLIC UTILITIES

OVERVIEW

Riverside Public Utilities generates, transmits and distributes electricity to a 81.5-square-mile territory that includes the City of Riverside. We also deliver water to a 74.2-square-mile territory covering the majority of the City of Riverside.

The Board of Public Utilities is comprised of nine volunteers who live in all seven wards of the City of Riverside. They are appointed by the City Council to four-year terms without compensation. Board members oversee Riverside Public Utilities' policies, operations, revenues, expenditures, planning, and regulatory compliance. They provide an ongoing, year-round review of all actions by Riverside Public Utilities before any measure is sent to the elected City Council representatives for final determination.

SERVICE AREA POPULATION

320,278

RECORD PEAK DEMAND

Energy: 658 megawatts
9/6/2024

Water: 365 acre feet
119 million gallons
8/9/2005

TOTAL OPERATING REVENUE

Energy: $472.3 million

Water: $95.7 million

CUSTOMERS

Energy: 114,180

Water: 66,772

CREDIT RATING

Energy:	AA-	Fitch
	AA-	S&P Global
Water:	AA+	Fitch
	AA+	S&P Global
	Aa2	Moody's

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CITY OF RIVERSIDE PUBLIC UTILITIES

RiversidePublicUtilities.com

OUR MISSION

The City of Riverside Public Utilities Department is committed to the highest quality water and electric services at the lowest possible rates to benefit the community.

OUR VISION

Our customers will recognize Riverside Public Utilities as a unique community asset with a global reputation for innovation, sustainability and an enhanced quality of life.

OUR CORE VALUES

- Safety
- Honesty and Integrity
- Teamwork
- Professionalism
- Quality Service
- Creativity and Innovation
- Community Involvement
- Environmental Stewardship
- Inclusiveness and Mutual Respect

OUR FOCUS AREAS

RELIABILITY & RESILIENCY
Taking care of our infrastructure, so that it remains safe, and efficient.

AFFORDABILITY
Thriving financially while balancing affordable rates for our customers.

SUSTAINABILITY
Ensuring adequate power and water supply in the most environmentally responsible manner.

CUSTOMER EXPERIENCE
Continuing to provide reliable customer-centered service every day.

OPERATIONAL EXCELLENCE
Implementing new technologies that will enhance the customer experience and ensure the tradition of operational excellence.

STRONG WORKFORCE
Developing and supporting a workforce that is safe, prepared and engaged.

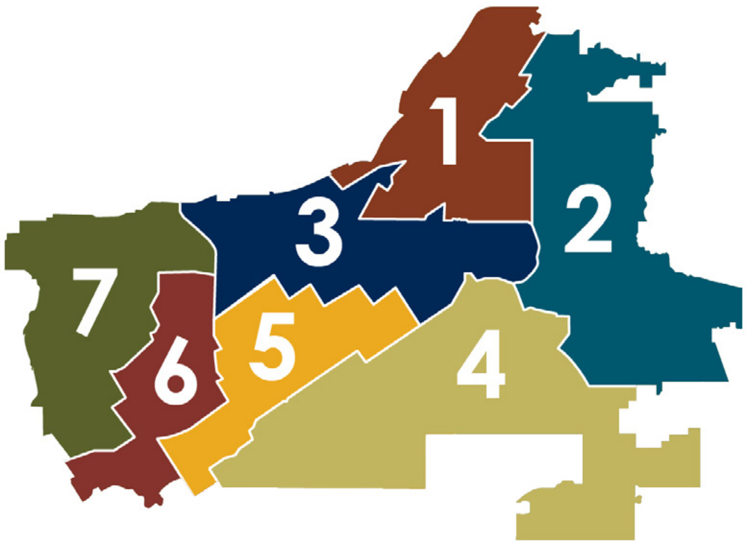
CITY COUNCIL

Patricia Lock Dawson
Mayor

- Philip Falcone
  Ward 1
- Clarissa Cervantes
  Ward 2
- Steven Robillard
  Ward 3
- Chuck Conder
  Ward 4
- Sean Mill
  Ward 5
- Jim Perry
  Ward 6
- Steve Hemenway
  Ward 7

BOARD OF PUBLIC UTILITIES

- Rebeccah A. Goldware
  (Board Chair)
  Ward 2
- Brian D. Siana
  (Board Vice Chair)
  Citywide/Ward 2
- Jordan Wright
  Ward 1
- Warren Avery
  Ward 3
- Gary Montgomery
  Ward 4
- Tom Evans
  Ward 5
- Vacant
  Ward 6
- Mikael Becker
  Ward 7
- Peter Wohlgemuth
  Citywide / Ward 1



EXECUTIVE MANAGEMENT

Mike Futrell
City Manager

Rafael Guzman
Assistant City Manager

David A. Garcia
Utilities General Manager

Brian Seinturier
Utilities Assistant General Manager
Finance and Administration

Daniel Honeyfield
Utilities Assistant General Manager
Energy Delivery

Scott M. Lesch
Utilities Assistant General Manager
Power Resources

Robin Glenney
Utilities Assistant General Manager
Water Delivery

Tracy Soto
Utilities Assistant General Manager
Strategic Initiatives

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OUR ELECTRIC

RIVERSIDE PUBLIC UTILITIES

CliftonLarsonAllen LLP
CLAconnect.com

INDEPENDENT AUDITORS' REPORT

Honorable Mayor, Members of the City Council,
and Board of Public Utilities
City of Riverside
Riverside, California

Report on the Audit of the Financial Statements

Opinion

We have audited the accompanying financial statements of the Electric Utility Enterprise Fund (Electric Utility) of the City of Riverside, as of and for the years ended June 30, 2025 and 2024, and the related notes to the financial statements, as listed in the table of contents.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Electric Utility, as of June 30, 2025 and 2024, and the changes in its financial position and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

Basis for Opinion

We conducted our audits in accordance with auditing standards generally accepted in the United States of America (GAAS) and the standards applicable to financial audits contained in *Government Auditing Standards*, issued by the Comptroller General of the United States. Our responsibilities under those standards are further described in the *Auditors' Responsibilities for the Audit of the Financial Statements* section of our report. We are required to be independent of the Electric Utility and to meet our other ethical responsibilities, in accordance with the relevant ethical requirements relating to our audits. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Emphasis of Matter

Restatement

As described in Note 14 to the financial statements, the Electric Utility restated the beginning net position. Our opinions are not modified with respect to this matter.

As discussed in Note 1, the financial statements present only the Electric Utility and do not purport to, and do not present fairly the financial position of the City of Riverside, California, as of June 30, 2025, the changes in its financial position, or, where applicable, its cash flows for the year then ended in accordance with accounting principles generally accepted in the United States of America. Our opinion is not modified with respect to this matter.

Responsibilities of Management for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with accounting principles generally accepted in the United States of America, and for the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion. Reasonable assurance is a high level of assurance but is not absolute assurance and therefore is not a guarantee that an audit conducted in accordance with GAAS and *Government Auditing Standards* will always detect a material misstatement when it exists. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control. Misstatements are considered material if there is a substantial likelihood that, individually or in the aggregate, they would influence the judgment made by a reasonable user based on the financial statements.

In performing an audit in accordance with GAAS and *Government Auditing Standards*, we:

- Exercise professional judgment and maintain professional skepticism throughout the audit.

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, and design and perform audit procedures responsive to those risks. Such procedures include examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Electric Utility's internal control. Accordingly, no such opinion is expressed.

- Evaluate the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluate the overall presentation of the financial statements.

We are required to communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit, significant audit findings, and certain internal control related matters that we identified during the audit.

Honorable Mayor and
Members of the City Council
City of Riverside

Required Supplementary Information

Accounting principles generally accepted in the United States of America require that the management's discussion and analysis, the schedule of proportionate share of the net pension liability, the schedule of contributions of the defined benefit plans, and the schedule of the Electric Utility's proportionate share of the City's Total OPEB liability of the OPEB plan be presented to supplement the basic financial statements. Such information is the responsibility of management and, although not a part of the basic financial statements, is required by the Governmental Accounting Standards Board who considers it to be an essential part of financial reporting for placing the basic financial statements in an appropriate operational, economic, or historical context. We have applied certain limited procedures to the required supplementary information in accordance with GAAS, which consisted of inquiries of management about the methods of preparing the information and comparing the information for consistency with management's responses to our inquiries, the basic financial statements, and other knowledge we obtained during our audit of the basic financial statements. We do not express an opinion or provide any assurance on the information because the limited procedures do not provide us with sufficient evidence to express an opinion or provide any assurance.

Other Information

Management is responsible for the other information included in the annual report. The other information comprises the introductory section and operating statistical section but does not include the basic financial statements and our auditors' report thereon. Our opinion on the basic financial statements do not cover the other information, and we do not express an opinion or any form of assurance thereon.

In connection with our audit of the basic financial statements, our responsibility is to read the other information and consider whether a material inconsistency exists between the other information and the basic financial statements, or the other information otherwise appears to be materially misstated. If, based on the work performed, we conclude that an uncorrected material misstatement of the other information exists, we are required to describe it in our report.

Other Reporting Required by *Government Auditing Standards*

In accordance with *Government Auditing Standards*, we have also issued our report dated December 23, 2025, on our consideration of the City of Riverside's internal control over financial reporting and on our tests of its compliance with certain provisions of laws, regulations, contracts, and grant agreements and other matters. The purpose of that report is solely to describe the scope of our testing of internal control over financial reporting and compliance and the results of that testing, and not to provide an opinion on the effectiveness of the City of Riverside's internal control over financial reporting or on compliance. That report is an integral part of an audit performed in accordance with *Government Auditing Standards* in considering City of Riverside's internal control over financial reporting and compliance.

CliftonLarsonAllen LLP

CliftonLarsonAllen LLP

Irvine, California
December 23, 2025


ALWAYS
WEAR
YOUR
GLOVES

ELECTRIC UTILITY:
MANAGEMENT'S DISCUSSION AND ANALYSIS

As management of Riverside Public Utilities, a department of the City of Riverside (the City), we offer the readers this narrative overview and analysis of the 2024-25 financial report for the periods ended June 30, 2025 and 2024 for Riverside's Electric Utility (Electric Utility), an enterprise fund of the City. We encourage readers to consider the information presented here in conjunction with additional information furnished in our financial statements, which begin on page 33 of this report. All amounts, unless otherwise indicated, are expressed in thousands of dollars.

FINANCIAL HIGHLIGHTS

- For fiscal year 2023-24 a prior period restatement was made to adjust the beginning net position, reflecting corrections of the capitalization of assets previously placed into service along with the related accumulated depreciation, and customer deposits held for developer funded capital projects within the Electric Utility. Impacted sections of this report have been revised to reflect the associated changes. For further details on the restatement, see Note 14 in the accompanying financial statements.

- GASB Statement No. 101, *Compensated Absences* - For the year ended June 30, 2025, the financial statements include the adoption of GASB Statement No. 101. This Statement requires that liabilities for compensated absences be recognized for (1) leave that has not been used and (2) leave that has been used but not yet paid in cash or settled through noncash means. It also requires that a liability for certain types of compensated absences - including parental leave, military leave, and jury duty leave - not be recognized until the leave commences. This Statement also requires that a liability for specific types of compensated absences not be recognized until the leave is used. Further, this Statement establishes guidance for measuring a liability for leave that has not been used, generally using an employee's pay rate as of the date of the financial statements. Refer to Note 5 for additional information.

- Retail sales, net of uncollectibles and recoveries, were $392,344 and $350,036 for years ended June 30, 2025 and 2024, respectively. The increase reflects approved rate plan adjustments, higher customer consumption, and the implementation of an enhanced methodology for estimating unbilled revenue at year-end.

- Investment income on investments of $27,187 increased by $8,472 due to a fair market value adjustment of investments and a higher overall interest rate in the current fiscal year.

- Operating expense related to production and purchased power of $186,418 decreased by $13,148 primarily due to lower forward market energy prices for purchased power. Due to fuel restrictions on the IPP coal asset throughout 2023, the Electric Utility needed to forward hedge significantly more energy for fiscal year 2023-24 at higher prevailing forward market energy prices. Compared to fiscal year 2023-24, forward and spot market energy prices for fiscal year 2024-25 were materially lower, contributing to lower puchased power costs in fiscal year 2024-25.

- Operating expense reflects a non-cash pension accounting standard adjustment, which will continue to fluctuate based on yearly actuarial information provided by the California Public Employees' Retirement System. The adjustment was $9,584 and $7,707 at June 30, 2025 and 2024, respectively.

- In fiscal year 2024-25, Southern California Edison (SCE) provided the 2024 Decommissioning Cost Estimate report for the life of the San Onofre Nuclear Generating Station (SONGS) decommissioning project. As a result, the Electric Utility recognized an increase in decommissioning liability expense of $5,807 as of June 30, 2025 due to a material increase in costs related to the SONGS Decommissioning project. See Note 10 in the accompanying financial statements for additional information.

OVERVIEW OF THE FINANCIAL STATEMENTS

This discussion and analysis is intended to serve as an introduction to the Electric Utility's financial statements. The Electric Utility is a department of the City, and its activities are recorded in a separate enterprise fund. These financial statements include only the activities for the Electric Utility and provide comparative information for the last two fiscal years. Information on city-wide financial results is available in the City's "Annual Comprehensive Financial Report" (ACFR).

The Electric Utility's financial statements are comprised of two components: 1) financial statements, and 2) notes to the financial statements. In addition, this report also contains other supplementary information to provide the reader additional information about the Electric Utility, including historical sales, operating activities, and other relevant data.

ELECTRIC UTILITY:
MANAGEMENT'S DISCUSSION AND ANALYSIS

Included as part of the financial statements are three separate statements, which collectively provide an indication of the Electric Utility's financial health.

The ***Statements of Net Position*** present information on all of the Electric Utility's assets, liabilities, deferred inflows and outflows of resources and net position. The Statements of Net Position provide information about the nature and amount of the Electric Utility's resources and obligations at a specific point in time.

The ***Statements of Revenues, Expenses and Changes in Net Position*** report all of the Electric Utility's revenues and expenses for the periods shown.

The ***Statements of Cash Flows*** report the cash provided and used by operating activities, as well as other cash sources, such as investment income and debt financing. They also report other cash uses such as payments for bond principal and capital additions and improvements.

The ***Notes to the Financial Statements*** provide additional information that is essential to a full understanding of the data provided in the financial statements. The Notes to the Financial Statements can be found on pages 39 to 81 of this report.

ELECTRIC UTILITY:
MANAGEMENT'S DISCUSSION AND ANALYSIS

ELECTRIC UTILITY FINANCIAL ANALYSIS

CONDENSED STATEMENTS OF NET POSITION

	2025	2024	2023
Current and other assets	$ 625,071	$ 602,487	$ 454,579
Capital assets	797,470	775,591	785,321
Deferred outflows of resources	31,817	34,671	45,624
Total assets and deferred outflows of resources	1,454,358	1,412,749	1,285,524
Long-term debt outstanding	686,221	712,106	590,602
Other liabilities	195,055	176,811	174,333
Deferred inflows of resources	12,526	15,671	17,237
Total liabilities and deferred inflows of resources	893,802	904,588	782,172
Net investment in capital assets	239,920	229,507	254,225
Restricted	105,693	94,234	74,163
Unrestricted	214,943	184,420	174,964
Total net position	$ 560,556	$ 508,161	$ 503,352

ASSETS AND DEFERRED OUTFLOWS OF RESOURCES

2025 compared to 2024 The Electric Utility's total assets and deferred outflows of resources were $1,454,358, reflecting an increase of $41,609 (2.9%), primarily due to the following:

- Current and other assets, comprised of restricted and unrestricted assets, had a net increase of $22,584, primarily due to increases of $18,617 in unrestricted cash and cash equivalents due to positive operating results, $14,981 in accounts receivable, $5,462 in prepaid expenses, and $5,436 in restricted cash and cash equivalents. The net increase was offset by the use of $29,785 in restricted bond proceeds to fund capital projects.
- Capital assets increased by $21,879 primarily due to an increase of $55,616 in additions and improvements to the Electric distribution infrastructure system to improve service and reliability to the Electric Utility's customers, offset by current year accumulated depreciation of $33,994. Additional capital asset information can be found in the "Capital Assets and Debt Administration" section.
- Deferred outflows of resources decreased by $2,854 primarily due to decreases in deferred outflows related to pension. Additional information can be found in the "Pension Expenses and Deferred Outflows/Inflows of Resources Related to Pension" section of Note 6 Employee Retirement Plan.

2024 compared to 2023 Total assets and deferred outflows of resources were $1,412,749, reflecting an increase of $127,225 (9.9%), primarily due to the following:

- Current and other assets, comprised of restricted and unrestricted assets, had a net increase of $147,908, primarily due to the issuance of the 2023 and 2024 Electric Revenue Series A Bonds, which fully refunded the 2008 Electric Revenue Series A and C Bonds, 2011 Electric Revenue Series A Bonds, and 2013 Electric Revenue Series A Bonds, along with new financing of capital projects for the Electric Utility. Additionally, there were increases of $10,369 in unrestricted cash and cash equivalents, as well as $3,510 in restricted cash and investments at fiscal agent for money's held for the future payment of pension related costs.
- Capital assets decreased by $9,730 primarily due to current year accumulated depreciation of $36,141 offset by an increase of $26,406 in additions and improvements to the Electric distribution infrastructure system to improve service and reliability to the Electric Utility's customers.
- Deferred outflows of resources decreased by $10,953 primarily due to decreases of $3,913 in deferred outflows related to pension, $5,375 from the loss on refundings, and $1,571 in the fair market value of interest rate swaps.

LIABILITIES AND DEFERRED INFLOWS OF RESOURCES

2025 compared to 2024 The Electric Utility’s total liabilities and deferred inflows of resources were $893,802, a decrease of $10,786 (1.2%), due to the following:

- Long-term debt outstanding decreased by $25,885 primarily due to principal payments on revenue bonds and pension obligation bonds. Additional debt information can be found in the “Capital Assets and Debt Administration” section.
- Other liabilities increased by $18,244 primarily due to increases of $8,680 in net pension liability, $4,490 in accounts payable, and $3,482 in unearned revenue.
- Deferred inflows of resources decreased by $3,145 primarily due to pension related adjustments, which included the changes in assumptions, the differences between expected and actual experience and the change in projected versus actual earnings on pension plan investments as determined by the plan actuary.

2024 compared to 2023 Total liabilities and deferred inflows of resources were $904,588, an increase of $122,416 (15.7%), due to the following:

- Long-term debt outstanding increased by $121,504 primarily due to the issuance of the 2023 and 2024 Electric Revenue Series A Bonds, which was partially offset by the full refunding of the 2008 Electric Revenue Series A and C Bonds, 2011 Electric Revenue Series A Bonds, and the 2013 Electric Revenue Series A Bonds.
- Other liabilities increased by $2,478 primarily due to increases of $5,479 in net pension liability and $4,733 in accrued interest payable due to the 2023 and 2024 Electric Revenue Series A bond issuances. The increase was offset by decreases of $4,097 in interest rate swaps due to the refunding of the 2008 Electric Revenue Series A and C Bonds and 2011 and 2013 Electric Revenue Series A Bonds, and $2,791 in nuclear decommissioning liability.
- Deferred inflows of resources decreased by $1,566 primarily due to pension related adjustments, which included the changes in assumptions, the differences between expected and actual experience and the change in projected versus actual earnings on pension plan investments as determined by the plan actuary.

NET POSITION

2025 compared to 2024 The Electric Utility’s net position, which represents the difference between the Electric Utility’s total assets and deferred outflows of resources less total liabilities and deferred inflows of resources, totaled $560,556, an increase of $52,395 (10.3%). The following represents the changes in components of net position:

- The largest portion of the Electric Utility’s total net position, $239,920 (42.8%), an increase of $10,413, reflects its net investment in capital assets less any related outstanding debt used to acquire those assets. Additional capital asset information can be found in the “Capital Assets and Debt Administration” section.
- The restricted portion of net position totaled $105,693 (18.9%), an increase of $11,459, and represents resources that are subject to external restrictions on how they may be used. These are reserved for items such as debt payments, Public Benefit Programs, and other legally restricted assets.
- The unrestricted portion of net position totaled $214,943 (38.3%), an increase of $30,523, which is primarily attributable to positive operating results, an increase in investment income, and the use of bond proceeds to fund qualifying capital projects. Unrestricted net position may be used to meet the Electric Utility’s ongoing operational needs and obligations to customers and creditors.

ELECTRIC UTILITY: MANAGEMENT'S DISCUSSION AND ANALYSIS

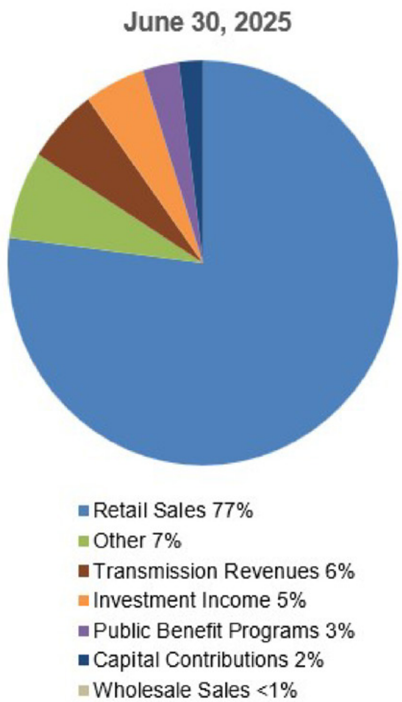
2024 compared to 2023 Total net position increased by $4,809 (1.0%), to a total of $508,161. The following represents the changes in components of net position:

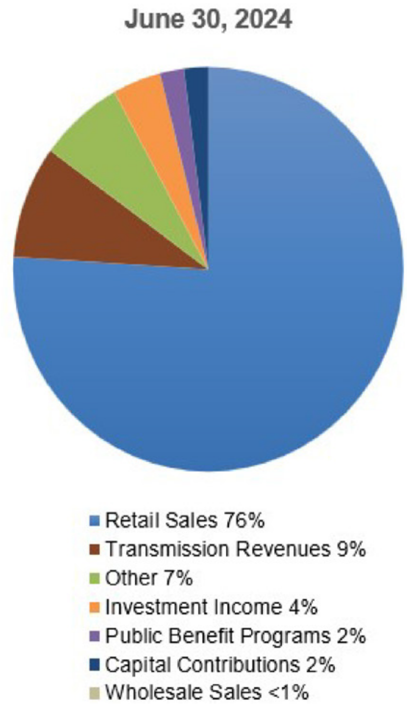
- The largest portion of the Electric Utility's total net position, $229,507 (45.2%), a decrease of $24,718, reflects its net investment in capital assets.
- The restricted portion of net position totaled $94,234 (18.5%), an increase of $20,071, and represents resources that are subject to external restrictions on how they may be used. These are reserved for items such as debt payments, Public Benefit Programs, and other legally restricted assets.
- The unrestricted portion of net position totaled $184,420 (36.3%), an increase of $9,456, which is primarily attributable to the use of bond proceeds to fund qualifying capital projects and positive operating results. Unrestricted net position may be used to meet the Electric Utility's ongoing operational needs and obligations to customers and creditors.

CONDENSED STATEMENTS OF CHANGES IN NET POSITION

	2025	2024	2023
Revenues:			
Retail sales, net	$ 392,344	$ 350,036	$ 347,016
Wholesale sales	7	-	2,043
Transmission revenue	32,749	39,934	35,233
Investment income	27,187	18,715	5,952
Other revenues	38,282	30,113	30,747
Public Benefit Programs	13,289	11,328	10,222
Capital contributions	8,745	7,553	9,854
Total revenues	512,603	457,679	441,067
Expenses:			
Production and purchased power	186,418	199,566	195,914
Transmission	54,284	54,248	68,052
Distribution	88,244	81,005	68,057
Public Benefit Programs	10,473	8,174	6,751
Depreciation	39,371	38,081	38,189
Amortization	260	200	200
Interest expenses and fiscal charges	30,136	25,934	23,775
Decommissioning liability expense	5,807	-	-
Total expenses	414,993	407,208	400,952
Transfers to the City's general fund	(45,215)	(45,289)	(42,326)
Changes in net position	52,395	5,182	(2,211)
Net position, July 1, as previously reported	508,161	503,352	505,563
Error correction	-	(373)	-
Net position, July 1, as restated	508,161	502,979	505,563
Net position, June 30	$ 560,556	$ 508,161	$ 503,352

REVENUES BY SOURCES





2025 compared to 2024 The Electric Utility's total revenues of $512,603 increased by $54,924 (12.0%) with changes in the following:

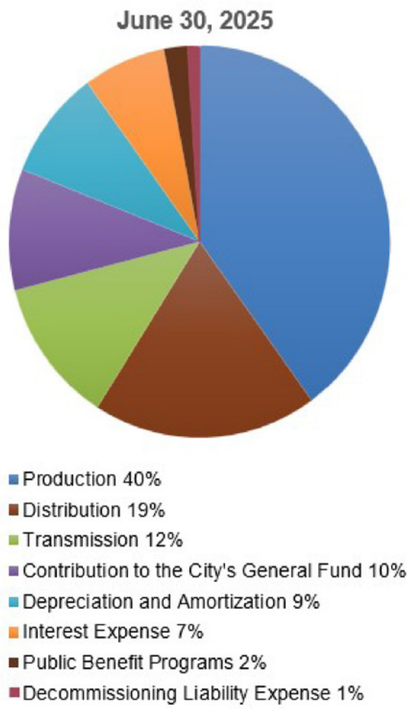
- Retail sales (residential, commercial, industrial, and others), net of uncollectibles and recoveries, totaled $392,344, a $42,308 (12.1%) increase. Retail sales continue to be the primary revenue source for the Electric Utility. The increase was due to approved rate plan adjustments, higher customer consumption, and the implementation of an enhanced methodology for estimating unbilled revenue at year-end.
- Transmission revenues of $32,749 decreased by $7,185 (18.0%) primarily due to lower High Voltage Transmission Revenue Requirement rates for the Electric Utility.
- Other revenues of $38,282 increased by $8,169 (27.1%), primarily due to an increase in Resource Adequacy (RA) sales as a result of significant upward price pressure in the RA market and miscellaneous service revenues.
- Investment income on investments increased by $8,472 due to a fair market value adjustment of investments and an increase due to a higher overall interest rate in the current fiscal year.

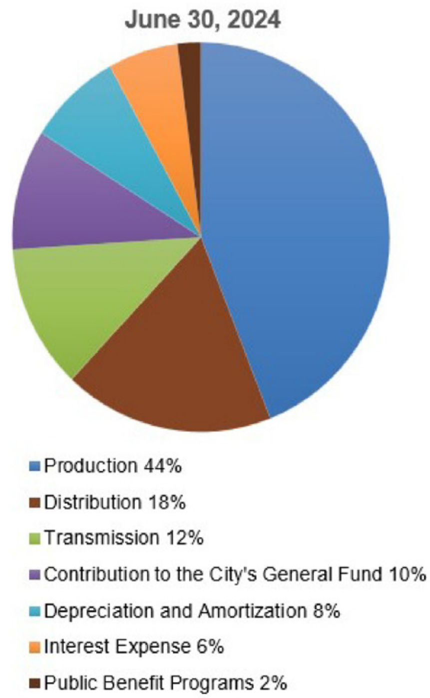
2024 compared to 2023 Total revenues of $457,679 increased by $16,612 (3.8%) with changes in the following:

- Retail sales (residential, commercial, industrial, and others), net of uncollectibles/recovery, totaled $350,036, a $3,020 (0.9%) increase. Retail sales continue to be the primary revenue source for the Electric Utility. The increase in sales was primarily due to rate plan increases offset by decreased consumption.
- Transmission revenues of $39,934 increased by $4,701 (13.3%) primarily due to Southern California Edison Existing Transmission Contract pass through and true-up costs, resulting in a higher High Voltage Transmission Revenue Requirement rate for the Electric Utility.
- Other revenues of $30,113 decreased by $634 (2.1%), primarily due to decreases in greenhouse gas cap-and-trade auction proceeds.
- Investment income on investments increased by $12,763 due to a fair market value adjustment of investments and a higher overall interest rate in the current fiscal year.

ELECTRIC UTILITY:
MANAGEMENT'S DISCUSSION AND ANALYSIS

EXPENSES BY SOURCES





2025 compared to 2024 The Electric Utility’s total expenses, excluding general fund transfer, were $414,993, an increase of $7,785 (1.9%). Expenses of significance are the following:

- Production and purchased power expenses of $186,418 decreased by $13,148 (6.6%) primarily due to lower forward market energy prices for purchased power. Due to fuel restrictions on the IPP coal asset throughout 2023, the Electric Utility needed to forward hedge significantly more energy for fiscal year 2023-24 at higher prevailing forward market energy prices. Compared to fiscal year 2023-24, forward and spot market energy prices for fiscal year 2024-25 were materially lower, contributing to lower puchased power costs in fiscal year 2024-25.
- Transmission expenses of $54,284, comprised of operating and maintenance costs, slightly increase from prior year.
- Distribution expenses of $88,244 increased by $7,239 (8.9%), mainly due to a non-cash pension adjustment of $9,584 compared to prior year of $7,707 as a result of pension accounting standards, along with increases in administrative and general operating expenses.
- Decommissioning liability expense increased by $5,807 due to a material increase in costs related to the SONGS Decommissioning project based on the 2024 Decommissioning Cost Estimate report. See Note 10 in the accompanying financial statements for additional information.

2024 compared to 2023 The Electric Utility’s total expenses, excluding general fund transfer, were $407,208, an increase of $6,256 (1.6%). The increase was primarily due to the following:

- Production and purchased power expenses of $199,566 increased by $3,652 (1.9%) primarily due to fuel restrictions on our Intermountain Power Project coal resource throughout fiscal year 2023-24 that forced the utility to forward hedge significantly more energy.
- Transmission expenses of $54,248 decreased by $13,804 (20.3%) mainly due to a decrease in Southern California Edison's high voltage rate and a decrease in the load from the California Independent System Operator (CAISO).
- Distribution expenses of $81,005 increased by $12,948 (19.0%), mainly due to a non-cash pension adjustment of $7,707 compared to prior year of $(1,308) as a result of pension accounting standards, along with increases in administrative and general operating expenses.

TRANSFERS

Pursuant to the City of Riverside Charter, the Electric Utility may transfer up to 11.5 percent of prior year's gross operating revenues, including adjustments, to the City's general fund. The City uses these funds to help provide needed public services to the residents of the City, including police, fire, parks, libraries and other benefits. The Electric Utility transferred $45,215 and $45,289 for 2025 and 2024, respectively, based on the gross operating revenue provisions in the City's Charter. Additional information can be found in Note 12 of the accompanying financial statements.

CAPITAL ASSETS AND DEBT ADMINISTRATION

CAPITAL ASSETS

The Electric Utility's investment in capital assets includes investments in production, transmission, and distribution related facilities, land, intangibles, construction in progress, as well as general items such as office equipment, furniture, etc.

The following table summarizes the Electric Utility's capital assets, net of accumulated depreciation, at June 30:

	2025	2024	2023
Utility plant			
Production	$ 122,028	$ 127,494	$ 136,413
Transmission	35,932	29,032	30,039
Distribution	423,694	400,017	408,103
General	61,663	61,272	63,030
Intangibles	2,886	5,736	8,032
Land	56,529	56,435	56,386
Intangibles, non-amortizable	10,651	10,651	10,651
Construction in progress	83,420	84,543	72,262
Total utility plant	796,803	775,180	784,916
Lease assets [1]			
Land	418	-	-
Building	51	125	199
Machinery and equipment	144	162	156
Subscription-based information technology arrangements	54	123	50
Total lease assets	667	410	405
Total capital assets	$ 797,470	$ 775,591	$ 785,321

[1] GASB 87 *Leases* was implemented effective July 1, 2021. GASB 96 *Subscription-Based Information Technology Arrangements* (SBITA) was implemented effective July 1, 2022. For additional information, refer to Notes 1 and 13.

2025 compared to 2024 The Electric Utility's investment in capital assets, net of accumulated depreciation, was $797,470, an increase of $21,879 (2.8%). The increase resulted primarily from the following significant capital projects, offset by current year depreciation:

- $19,752 in substation improvements, including the Hunter Substation project.
- $19,098 in recurring expenditures such as transformer replacements, cable replacements, and the Riverside Transmission Reliability Project for additional generation import capability for a second point of interconnection with the State's high voltage transmission grid.
- $9,831 in underground improvements, such as distribution line extensions and underground cable replacements.
- $2,172 in donated underground electrical conduit, donated street lighting, and donated land rights and easement.

2024 compared to 2023 Investment in capital assets, net of accumulated depreciation, was $775,591, a decrease of $9,730 (1.2%). The decrease resulted primarily from the current year depreciation offset by the following significant capital projects:

- $8,528 in recurring expenditures such as transformer replacements, cable replacements, and the Riverside Transmission Reliability Project for additional generation import capability for a second point of interconnection with the State's high voltage transmission grid.
- $5,305 in substation improvements.
- $5,079 in underground improvements, such as distribution line extensions and underground cable replacements.
- $2,852 in donated underground electrical conduit, donated street lighting, and donated land rights and easement.

Additional information regarding capital assets can be found in Notes 3 and 13 of the accompanying financial statements.

DEBT ADMINISTRATION

The following table summarizes outstanding long-term debt as of June 30:

	2025	2024	2023
Revenue bonds	$ 582,675	$ 600,680	$ 507,370
Unamortized premium	72,717	76,815	42,457
Arbitrage liability	2,527	-	-
Pension obligation bonds	52,616	58,291	63,408
Less: Current portion of outstanding debt	(24,314)	(23,680)	(22,633)
Total long-term debt	$ 686,221	$ 712,106	$ 590,602

The Electric Utility's bond indentures require the Electric Utility to maintain a minimum debt service coverage ratio, as defined by the bond covenants, of 1.10. The Electric Utility's debt service coverage ratio was 3.20, 2.31, and 2.01 at June 30, 2025, 2024 and 2023, respectively. This debt is backed by the revenues of the Electric Utility. Debt service coverage ratio increased at June 30, 2025 due to positive operating results, offset by increases in principal and interest payments on debt service.

2025 compared to 2024 The Electric Utility's long-term debt decreased by $25,885 (3.6%) to $686,221 as a result of current year principal payments and amortization of bond premiums, offset by an increase in arbitrage liability.

2024 compared to 2023 Long-term debt increased by $121,504 (20.6%) to $712,106 as a result of the new bond issuances.

During fiscal year 2023-24, two bonds were issued for the Electric Utility, 2023 Electric Revenue Refunding Bond Series A and 2024 Electric Revenue Bond Series A. In December 2023, the 2023 Electric Revenue Bonds Series A with $31,390 principal were issued to fully refund the 2013 Electric Revenue Bonds Series A. In February 2024, the 2024 Electric Revenue Bonds Series A with $213,295 principal were issued to fully refund the 2008 Electric Revenue Bonds Series A and C and 2011 Electric Revenue Bonds Series A. The 2024 Electric Revenue Bonds Series A also includes new funding for qualifying electric capital projects. As of June 30, 2024, the Electric Utility debt portfolio no longer holds any variable rate bonds.

Additional information on the Electric Utility's long-term debt can be found in Note 4 of the accompanying financial statements and Key Historical Operating Data section.

CREDIT RATINGS

The Electric Utility maintains a credit rating of "AA-" from S&P Global Ratings (S&P) and "AA-" from Fitch Ratings (Fitch). These ratings are a result of the Electric Utility's evolving power resource portfolio, which is well positioned to meet California's increasing environmental regulations with an emphasis on renewable energy resources, stable financial performance and strong liquidity levels.

REGULATORY, LEGISLATIVE FACTORS, AND RATES

Utilities are faced with ongoing regulatory and legislative mandates enacted at the federal and state level that will have significant impact on the operations of the Electric Utility.

ASSEMBLY BILL (AB) 32 – GLOBAL WARMING SOLUTIONS ACT OF 2006

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

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

The Program requires electric utilities to have GHG allowances on an annual basis to offset GHG emissions associated with generating electricity. CARB will provide a free allocation of GHG allowances to each electric utility to mitigate retail rate impacts. If a utility requires additional allowances, then they must be purchased through the auction or on the secondary market to offset its associated GHG emissions. Each allowance can be used for compliance purposes in the current year or carried over for use for future year compliance. The Electric Utility's free allocation of GHG allowances is expected to be sufficient to meet the Electric Utility's direct GHG compliance obligations.

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

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

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

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

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

In November 2024, CARB adopted amendments to the LCFS regulation that went into effect on July 1, 2025. Under the new amendments, the CFR Program will now provide point-of-purchase rebates for new and/or used commercial medium- or heavy-duty EVs rather than new light-duty EVs. Additionally, the Electric Utility has been reclassified as a small publicly owned utility and will no longer have an obligation to contribute funds to the CFR Program, although its customers are still eligible to participate in the program. The approved amendments also included changes to the list of preapproved projects for holdback credits and no longer provides credits for electric forklift charging to electric utilities.

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

SENATE BILL (SB) 1368 – EMISSION PERFORMANCE STANDARD

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

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

Going forward, SB 1368 related issues are expected to have minimal impact to the CAISO markets as the percentage of California load served by coal resources is small. However, to the extent that significant numbers of coal plants throughout the western United States (U.S.) start to retire in the next 5 to 15 years, it is possible that there can be a tightening of supply throughout the western U.S. electricity market. In turn, this can lead to higher regional costs and potentially reduced system reliability.

ASSEMBLY BILL (AB) 2514 - ENERGY STORAGE

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

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

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

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

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

On September 11, 2017 and September 26, 2017, after reevaluating its assessment of the first adopted energy storage procurement target of zero megawatts, the Riverside Board and City Council, respectively, approved and adopted the second energy storage procurement target of six megawatts for submittal to the CEC.

SENATE BILL (SB) 380 – MORATORIUM ON NATURAL GAS STORAGE – ALISO CANYON

On October 23, 2015, a significant gas leak was discovered at the Aliso Canyon natural gas storage facility, which makes up 63% of total storage capacity and serves 17 gas fired power generation units. On May 10, 2016, the Governor of California signed SB 380 placing a moratorium on Aliso Canyon's natural gas storage usage until rigorous tests were performed and completed by the Division of Oil, Gas, and Geothermal Resources (DOGGR) as to which wells could continue to be in operation. This moratorium caused great concern regarding reliability in the upcoming summer and winter months. An action plan was initiated to review the summer and winter assessment. This action plan was conducted as a joint effort between the California Public Utilities Commission (CPUC), CEC, CAISO, and Los Angeles Department of Water and Power (LADWP). Although the area of study does not include nor immediately impact Riverside, it is highly plausible that the Electric Utility could still experience curtailed gas deliveries under certain adverse low-flow gas scenarios.

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

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

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

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

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

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

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

SENATE BILL (SB) 859 – "BUDGET TRAILER BILL" – BIOMASS MANDATE

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

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

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

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

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

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

SENATE BILL (SB) 350 – CLEAN ENERGY AND POLLUTION REDUCTION ACT OF 2015

SB 350, enacted in 2015, consists of a multitude of requirements to meet the Clean Energy and Pollution Reduction Act of 2015. The primary components that affect the Electric Utility are: 1) the increased mandate of the California RPS to 50% by December 31, 2030, 2) doubling of energy efficiency savings by January 1, 2030, and 3) providing for the transformation of the CAISO into a regional organization. In addition, there is a specific integrated resource planning mandate embedded in the bill that applies to the 16 POUs that have an annual electrical demand exceeding 700 GWh over a 3-year average, which includes the Electric Utility.

The bill also requires that an updated RPS Procurement Policy must be approved and adopted before January 1, 2019 and be incorporated into the Electric Utility's Integrated Resource Plan (IRP). An Updated 2018 Renewable Energy Procurement Policy was adopted by the Board and City Council on September 10, 2018 and October 9, 2018, respectively. In parallel, on or before January 1, 2019, the governing board of the Electric Utility must adopt an IRP and a process for updating the plan at least once every 5 years. The IRP must address specific topics such as energy efficiency and demand response resources, transportation electrification, GHG emissions, energy storage resources, enhanced distribution systems and demand-side management, etc. The IRP must be submitted to the CEC for review, of which the CEC will check if the statutory requirements have been met and will adopt guidelines to govern the submission of the IRP information. On August 9, 2017, the CEC adopted the POU IRP Submission and Review Guidelines.

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

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

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

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

ASSEMBLY BILL (AB) 1110 AND SENATE BILL (SB) 1158 - LEGISLATION RELATING TO GREENHOUSE GAS EMISSIONS REPORTING FOR POWER RESOURCE DISCLOSURE

On September 26, 2016, AB 1110 was signed into law requiring GHG emissions intensity data and unbundled renewable energy credits (RECs) to be included as part of the retail suppliers' power source disclosure (PSD) report and power content label (PCL) to their customers. GHG emissions intensity factors will need to be provided for all retail electricity products. The inclusion of this new information requirement on the PCL will begin in 2021 for calendar year 2020 data. In addition to still being required to post the PCL on the city website, the bill also reinstated the requirement that the PCL disclosures must be mailed to the customers starting in 2017 for calendar year 2016 data unless customers have opted for electronic notifications. In accordance with this requirement, Riverside reinstated the inclusion of printed disclosures of the PCL with its September 2017 bills to the customers.

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

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

ASSEMBLY BILL (AB) 398 – GHG CAP-AND-TRADE PROGRAM EXTENSION

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

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

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

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

ASSEMBLY BILL (AB) 617 – AIR QUALITY MONITORING

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

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

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

ASSEMBLY BILL (AB) 802 – BUILDING ENERGY USE BENCHMARKING AND PUBLIC DISCLOSURE PROGRAM

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

SENATE BILL (SB) 48 – BUILDING ENERGY SAVINGS ACT

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

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

SENATE BILL (SB) 100 – THE 100 PERCENT CLEAN ENERGY ACT OF 2018

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

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

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

SENATE BILL (SB) 1028, SB 901 AND ASSEMBLY BILL (AB) 1054 – LEGISLATION RELATING TO WILDFIRES

On September 24, 2016, Governor Brown signed into law SB 1028, which requires each POU, IOU and electric cooperative to construct, maintain, and operate its electrical lines and equipment in a manner that will minimize the risk of catastrophic wildfire posed by those electrical lines and equipment.

SB 901, which was passed at the end of the 2017-2018 biennium session of the California State Legislature and signed by the Governor on September 21, 2018, is meant to address the Governor’s and legislative leaders’ desire to address response, mitigation, and prevention of wildfires. SB 901 requires the Electric Utility to prepare before January 1, 2020 and annually thereafter, a wildfire mitigation plan (WMP) that includes specified information and elements. The Electric Utility must present its WMP in an appropriately noticed public meeting and accept comments on the plan from the public, other local and state agencies, and interested parties, and to verify that the plan complies with all applicable rules, regulations, and standards, as appropriate. In addition, the Electric Utility must contract with a qualified independent evaluator to review and assess the comprehensiveness of its plan. The report of the independent evaluator must be made available on the Electric Utility’s website and presented at the local governing board’s public meeting.

On July 12, 2019, the Governor signed into law AB 1054 and AB 111, which establishes the California Wildfire Safety Advisory Board (WSAB), adds an additional process requirement for review of wildfire mitigation plans, and establishes a wildfire fund. In addition to the Electric Utility presenting its WMP to its local governing board by January 1, 2020, the Electric Utility must submit it to the new advisory board by July 1, 2020 and provide annual updates each year thereafter. Additionally, the Electric Utility is required to submit a comprehensive WMP at least once every three years.

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

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

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

On June 27, 2022, the Riverside Board approved the 2022 WMP which was then submitted to the WSAB on June 30, 2022. On October 17, 2022, the WSAB issued a guidance advisory opinion for the 2023 WMP for electric POUs and rural electric cooperatives. The advisory opinion included general guidance that applied to all POUs, specific guidance for each POU, and a template with instructions for preparing 2023 plans. All guidance was incorporated into Riverside's 2023 WMP. The 2023 WMP included the steps, programs, policies, and procedures implemented by the Electric Utility to reduce wildfire risks and minimize impacts to customers. As required by PUC Section 8387, a qualified independent evaluator was contracted to review and assess the 2023 WMP for comprehensiveness. The independent evaluator provided feedback on the plan, which the Electric Utility incorporated by including additional details to further clarify the Electric Utility's wildfire mitigation measures. Afterwards, the independent evaluator concluded that the Electric Utility's 2023 WMP was sufficient in meeting the requirements for comprehensiveness. On June 26, 2023 and July 18, 2023, the 2023 WMP and independent evaluator's findings were presented to the Riverside Board and City Council, respectively. The 2023 WMP was submitted to the WSAB on July 19, 2023.

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

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

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

ASSEMBLY BILL (AB) 205 – ON-CALL RESOURCES AND ENERGY STORAGE

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

The initial DSGS program and guidelines launched in the Summer of 2022 and concluded October 2022. On July 26, 2023, the CEC adopted the second edition of the DSGS guidelines, which made the program effective immediately. On May 8, 2024, the CEC adopted the DSGS Guidelines, Third Edition. Through the program, participating customers receive a financial incentive for on-call load reduction during extreme events and the Electric Utility receives reimbursement for administrative costs to facilitate customer participation. The funding for the DSGS program was authorized by AB 205 and further expanded by AB 102 (signed on July 10, 2023), which stated the funding would be available for five years until June 30, 2027. On May 13, 2024 and June 11, 2024, the recommendation for the Electric Utility to allow customers to participate in a non-utility sponsored demand response program under the CEC DSGS state program was approved by the Riverside

Board and City Council, respectively. Following these approvals, the Electric Utility began authorization of enrolling customers in the CEC DSGS program. On April 10, 2025, the CEC adopted the DSGS Guidelines, Fourth Edition. The new guidelines did not affect the Electric Utility's participation in the program.

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

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

ASSEMBLY BILL (AB) 209 – ENERGY AND CLIMATE CHANGE

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

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

Another program under AB 209 that the CEC must establish and administer is the Hydrogen Program to provide financial incentives to in-state hydrogen projects for the demonstration or scale-up of the production, processing, delivery, storage, or end use of clean hydrogen. The CEC held a workshop in December 2022 to provide an overview of the Clean Hydrogen Program and the proposed program scope, funding areas, and project requirements. On May 19, 2023, the CEC released a draft solicitation concept for large-scale centralized production to solicit public feedback. On May 23, 2023, the CEC released the “Cost Share for Federal Clean Energy Funding Opportunities” competitive solicitation, which is ongoing. In May 2024, Governor Newsom released the 2024-2025 Revised State Budget Proposal, which called for reducing the Clean Hydrogen Program funding to $40 million and delaying the majority of funding until fiscal year 2025-26.

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

FIVE-YEAR ELECTRIC RATE PLAN

On September 19, 2023, the City Council approved a new five-year Electric Rate Plan, which includes system average annual rate increases. The first rate increase was effective January 1, 2024 with the following four years effective on January 1 of each year. The approved five-year Electric Rate Plan includes annual reviews of the adopted rates by City Council. The system average rate increases effective January 1, 2024 through 2026 are 7.0%, followed by system average rate increases of 2.0% in years four and five. The Electric Rate Plan was designed to provide financial stability and correct the imbalance of costs versus revenue recovery.

ELECTRIC UTILITY:
MANAGEMENT'S DISCUSSION AND ANALYSIS

ECONOMIC DEVELOPMENT AND GREEN INITIATIVES

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

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

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

The City has received numerous recognitions for its sustainability programs and initiatives. In 2009, the California Department of Conservation named Riverside its first "Emerald City" in recognition for its sustainable green initiatives and commitment to help the state achieve multiple state environmental priorities. The City was honored in 2016 with the Green Community Award from Audubon International, recognizing Riverside for its ongoing sustainability initiatives. In addition, the City received the 2016 Sustainable Communities Award from the Green California Leadership Summit for its ongoing community-wide sustainability projects and programs that create environmental awareness and action throughout the community, including business, government and private citizens. The Green California Leadership Summit again recognized the City in 2018 with its Leadership Award for the City Green Fleet Program. Additionally, in 2022, Riverside was ranked #1 in North America for the Green Fleet Award by the NAFA Fleet Management Association.

The Utility hosted its inaugural community Earth Day celebration in 2022. Subsequent Earth Days have been marked by community celebration days, hosted in collaboration with the City's Insect Fair. The RPU team was able to expand on its messaging and outreach by hosting several booths and interactive, hands-on experiences for attendees to learn in detail about water conservation and energy efficiency, and the changes they could make towards achieving these goals.

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

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

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

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

These economic development and sustainability projects and programs put the Electric Utility on the cutting edge of job creation and resource efficiency, making the City a better place to live and do business.

REQUESTS FOR INFORMATION

This financial report is designed to provide a general overview of the Electric Utility's finances. Questions concerning any information provided in this report or requests for additional financial information should be addressed to the Utilities Assistant General Manager – Finance and Administration, Riverside Public Utilities, 3750 University Avenue, 5th floor, Riverside, CA 92501. Additional financial information can also be obtained by visiting www.RiversideCA.gov/Utilities.

ELECTRIC UTILITY:
FINANCIAL STATEMENTS

STATEMENTS OF NET POSITION

ASSETS AND DEFERRED OUTFLOWS OF RESOURCES	June 30, 2025	June 30, 2024
	(in thousands)	
NON-CURRENT ASSETS:		
Capital assets:		
Utility plant, net of accumulated depreciation (Note 3)	$ 646,203	$ 623,551
Capital assets, not depreciated (Note 3)	150,600	151,630
Lease and subscription capital assets, net of amortization (Note 3 & 13)	667	410
Total capital assets	797,470	775,591
Restricted assets:		
Cash and investments at fiscal agent (Note 2)	48,258	48,530
Cash and cash equivalents at fiscal agent (Note 2)	97,958	127,743
Total non-current restricted assets	146,216	176,273
Other non-current assets:		
Advances to Successor Agency Trust Fund (Note 1)	1,098	1,555
Lease receivable (Note 13)	9,754	11,069
Unamortized purchase power (Note 11)	12,598	11,025
Regulatory assets	1,999	2,109
Total other non-current assets	25,449	25,758
Total non-current assets	969,135	977,622
CURRENT ASSETS:		
Unrestricted assets:		
Cash and cash equivalents (Note 2)	276,817	258,200
Accounts receivable, less allowance for doubtful accounts 2025 ($2,958); 2024 ($1,929)	56,786	41,805
Accrued interest receivable	2,037	1,626
Leases receivable (Note 13)	1,478	1,343
Inventory	1,313	1,464
Prepaid expenses	9,321	3,859
Unamortized purchase power (Note 11)	5,639	664
Total unrestricted current assets	353,391	308,961
Restricted assets:		
Cash and cash equivalents (Note 2)	63,677	58,241
Public Benefit Programs - cash and cash equivalents (Note 2)	34,710	32,033
Public Benefit Programs receivable	1,628	1,221
Total restricted current assets	100,015	91,495
Total current assets:	453,406	400,456
Total assets	1,422,541	1,378,078
DEFERRED OUTFLOWS OF RESOURCES:		
Deferred outflows related to pension (Note 6)	28,534	31,018
Deferred outflows related to other postemployment benefits (Note 7)	1,284	1,498
Loss on refunding	1,999	2,155
Total deferred outflows of resources	31,817	34,671
Total assets and deferred outflows of resources	$ 1,454,358	$ 1,412,749

See accompanying notes to financial statements

ELECTRIC UTILITY:
FINANCIAL STATEMENTS

STATEMENTS OF NET POSITION

NET POSITION, LIABILITIES AND DEFERRED INFLOWS OF RESOURCES	June 30, 2025 (in thousands)	June 30, 2024
NET POSITION:		
Net investment in capital assets	$ 239,920	$ 229,507
Restricted for:		
Regulatory requirements(Note 8)	41,762	34,261
Debt service (Note 8)	24,465	23,981
Unfunded accrued liability	4,169	3,510
Public Benefit Programs	35,297	32,482
Unrestricted	214,943	184,420
Total net position	560,556	508,161
LONG-TERM OBLIGATIONS, LESS CURRENT PORTION (Note 4)	686,221	712,106
OTHER NON-CURRENT LIABILITIES:		
Compensated absences (Note 5)	4,383	2,065
Net pension liability (Note 6)	52,907	44,227
Nuclear decommissioning liability (Note 10)	40,078	33,838
Other postemployment benefits liability (Note 7)	10,472	10,049
Lease liability (Note 13)	383	162
SBITA liability (Note 13)	-	46
Total other non-current liabilities	108,223	90,387
CURRENT LIABILITIES PAYABLE FROM RESTRICTED ASSETS:		
Accrued interest	7,313	9,816
Public Benefit Programs payable	1,026	750
Nuclear decommissioning liability (Note 10)	6,887	12,244
Current portion of long-term obligations (Note 4)	24,314	23,680
Total current liabilities payable from restricted assets	39,540	46,490
CURRENT LIABILITIES:		
Accounts payable and other accruals	25,776	21,286
Compensated absences (Note 5)	4,592	5,335
Customer deposits	12,109	11,972
Unearned revenue	4,244	762
Other postemployment benefits liability (Note 7)	335	397
Lease liability (Note 13)	190	132
SBITA liability (Note 13)	46	50
Total current liabilities	47,292	39,934
Total liabilities	881,276	888,917
DEFERRED INFLOWS OF RESOURCES:		
Deferred inflows related to pension (Note 6)	312	1,892
Deferred inflows related to other postemployment benefits (Note 7)	1,990	2,038
Lease related items (Note 13)	10,224	11,741
Total deferred inflows of resources	12,526	15,671
Total net position, liabilities and deferred inflows of resources	$ 1,454,358	$ 1,412,749

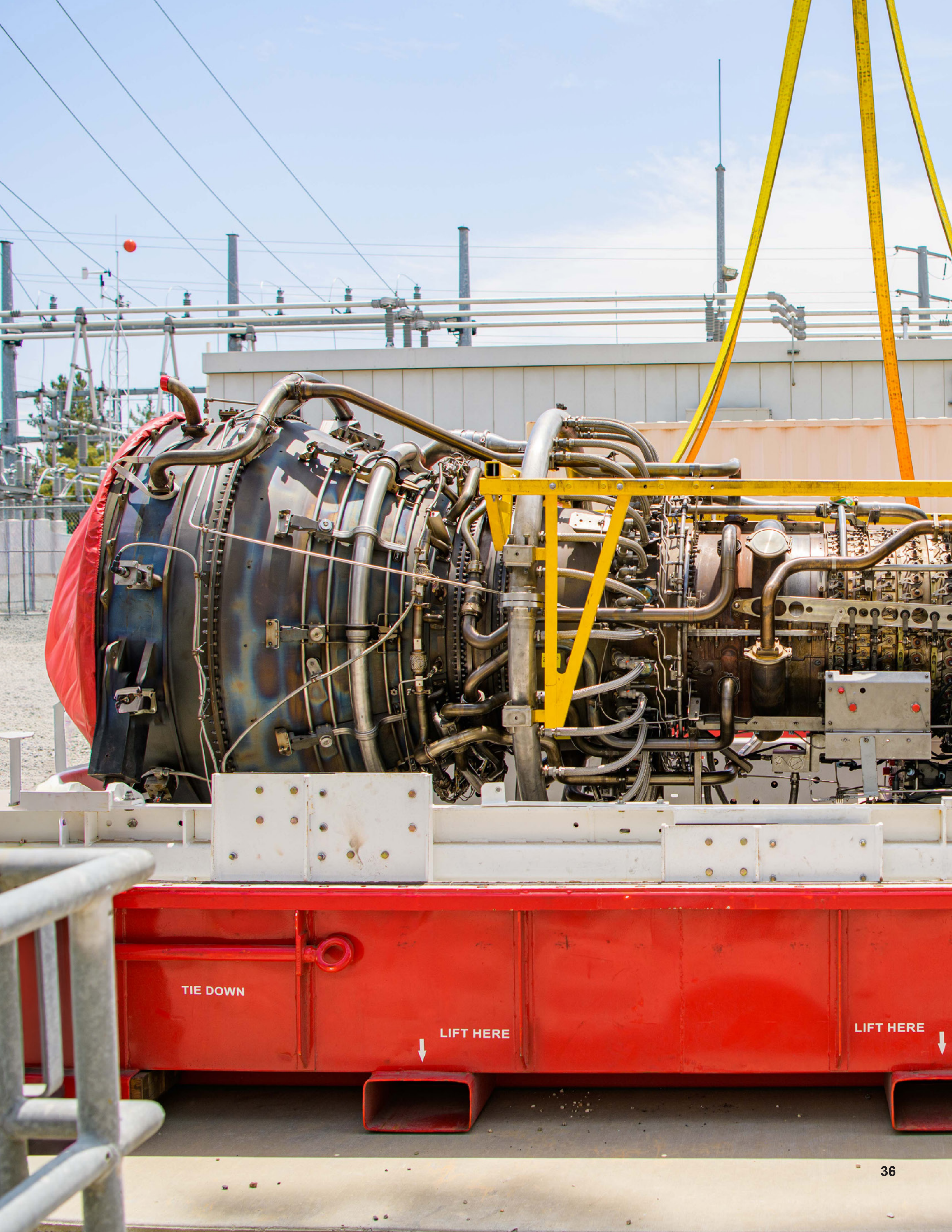
See accompanying notes to financial statements

ELECTRIC UTILITY:
FINANCIAL STATEMENTS

STATEMENTS OF REVENUES, EXPENSES AND CHANGES IN NET POSITION

	For the Fiscal Years Ended June 30, 2025 (in thousands)	2024
OPERATING REVENUES:		
Residential sales	$ 164,209	$ 138,879
Commercial sales	83,190	77,850
Industrial sales	142,845	130,519
Other sales	5,371	5,254
Wholesale sales	7	-
Transmission revenue	32,749	39,934
Other operating revenue	33,948	26,089
Public Benefit Programs	13,289	11,328
Total operating revenues before uncollectibles	475,608	429,853
Estimated uncollectibles, net of bad debt recovery	(3,271)	(2,466)
Total operating revenues, net of uncollectibles	472,337	427,387
OPERATING EXPENSES:		
Production and purchased power	186,418	199,566
Transmission	54,284	54,248
Distribution	88,244	81,005
Public Benefit Programs	10,473	8,174
Depreciation (Note 3)	39,371	38,081
Amortization (Note 3)	260	200
Total operating expenses	379,050	381,274
Operating income	93,287	46,113
NON-OPERATING REVENUES (EXPENSES):		
Investment (loss) income	27,187	18,715
Interest expense and fiscal charges	(30,136)	(25,934)
Decommissioning liability expense	(5,807)	-
Gain (loss) on sale of assets	(270)	429
Other	4,604	3,595
Total non-operating revenues (expenses)	(4,422)	(3,195)
Income before capital contributions and operating transfers out	88,865	42,918
Capital contributions	8,745	7,553
Transfers out - contributions to the City's general fund	(45,215)	(45,289)
Total capital contributions and transfers out	(36,470)	(37,736)
Change in net position	52,395	5,182
NET POSITION, BEGINNING OF YEAR, AS PREVIOUSLY STATED	508,161	503,352
ERROR CORRECTION (Note 14)	-	(373)
NET POSITION, BEGINNING OF YEAR, AS RESTATED	508,161	502,979
NET POSITION, END OF YEAR	$ 560,556	$ 508,161

See accompanying notes to financial statements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STATEMENTS OF CASH FLOWS

	For the Fiscal Years Ended June 30, 2025	2024
	(in thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
Cash received from customers and users	$ 460,969	$ 422,972
Cash paid to suppliers for goods and services	(283,269)	(279,077)
Cash paid to employees for services	(56,882)	(53,663)
Net cash provided/(used) by operating activities	**120,818**	**90,232**
CASH FLOWS FROM NON-CAPITAL FINANCING ACTIVITIES:		
Cash transfers out	(45,215)	(45,289)
Payment receipt from advances to other funds	457	448
Increase (decrease) in restricted arbitrage cash	(2,526)	-
Debt service payment on pension obligation bonds	(5,676)	(5,118)
Other non-operating receipts	4,268	3,296
Net cash provided/(used) by non-capital financing activities	**(48,692)**	**(46,663)**
CASH FLOWS FROM CAPITAL AND RELATED FINANCING ACTIVITIES:		
Acquisition and construction of capital assets	(59,466)	(26,457)
Principal paid on capital debt	(15,479)	(17,515)
Interest paid on capital debt	(33,948)	(23,600)
Payment to refunding escrow agent	-	(134,114)
Contributions	6,572	4,701
Proceeds from sales of capital assets	394	1,018
Lease and subscription payments	(302)	(241)
Proceeds from revenue bonds, including premium	-	283,940
Bond issuance costs	-	(4,588)
Net cash provided/(used) by capital and related financing activities	**(102,229)**	**83,144**
CASH FLOWS FROM INVESTING ACTIVITIES:		
Income (loss) from investments	26,776	18,122
Proceeds from/(purchase of) investment securities	272	9,605
Net cash provided/(used) by investing activities	**27,048**	**27,727**
Net increase/(decrease) in cash and cash equivalents	**(3,055)**	**154,440**
CASH AND CASH EQUIVALENTS, BEGINNING OF YEAR (including $218,017 and $64,587 at June 30, 2024 and June 30, 2023, respectively, reported in restricted accounts)	476,217	321,777
CASH AND CASH EQUIVALENTS, END OF YEAR (including $196,345 and $218,017 at June 30, 2025 and June 30, 2024, respectively, reported in restricted accounts)	$ 473,162	$ 476,217

See accompanying notes to financial statements

ELECTRIC UTILITY:
FINANCIAL STATEMENTS

STATEMENT OF CASH FLOWS

	For the Fiscal Years Ended June 30, 2025	2024
	(in thousands)	
RECONCILIATION OF OPERATING INCOME TO NET CASH PROVIDED BY OPERATING ACTIVITIES:		
Operating income (loss)	93,287	46,113
Adjustments to reconcile operating income/(loss) to net cash provided/(used) by operating activities:		
Depreciation	39,371	38,081
Amortization	260	200
(Increase) decrease in utility billed receivable	(2,298)	(588)
(Increase) decrease in utility unbilled receivable	(10,798)	(3,878)
(Increase) decrease in accounts receivable	(2,238)	229
(Increase) decrease in prepaid items	(11,877)	3,065
(Increase) decrease in deposits	(133)	(116)
(Increase) decrease in inventory	152	-
(Increase) decrease in intergovernmental receivable	351	(306)
Increase (decrease) in accounts payable	3,263	2,087
Increase (decrease) in accrued payroll	468	173
Increase (decrease) in retainage payable	762	(559)
Increase (decrease) in decommissioning liability	(4,924)	(2,791)
Increase (decrease) in Public Benefit Programs payable	276	(117)
Increase (decrease) in deposits payable	137	238
Increase (decrease) in unearned revenue	3,482	448
Increase (decrease) in compensated absences	1,575	(78)
Increase (decrease) in net pension liability	9,584	7,707
Increase (decrease) in OPEB liability	526	475
Increase (decrease) in Public Benefit Program receivable	(408)	(151)
Total adjustments	**27,531**	**44,119**
Net cash provided/(used) by operating activities	**$ 120,818**	**$ 90,232**
SCHEDULE OF NON-CASH INVESTING, CAPITAL AND FINANCING ACTIVITIES:		
Capital contributions - capital assets	$ 2,172	$ 2,852
(Increase) decrease in arbitrage rebate liability	(2,527)	-
Increase (decrease) in fair value of investments	1,809	1,111
Lease and subscription additions	518	257

See accompanying notes to financial statements

ELECTRIC UTILITY:
NOTES TO THE FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The Electric Utility exists under, and by virtue of, the City of Riverside (the City) Charter enacted in 1883. The Electric Utility is responsible for the generation, transmission, and distribution of electric power for sale in the City. The accompanying financial statements present only the financial position and the results of operations of the Electric Utility, which is an enterprise fund of the City, and are not intended to present fairly the financial position and results of operations of the City in conformity with generally accepted accounting principles. However, certain disclosures are for the City as a whole, since such information is generally not available for the Electric Utility on a separate fund basis. All amounts, unless otherwise indicated, are expressed in thousands of dollars.

BASIS OF ACCOUNTING

The Electric Utility uses the accrual basis of accounting as required for enterprise funds with accounting principles generally accepted in the United States of America as applicable to governments. The accounting records of the Electric Utility are also substantially in conformity with the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission (FERC). The Electric Utility is not subject to the regulations of the FERC.

The Electric Utility distinguishes operating revenues and expenses from non-operating items. Operating revenues and expenses generally result from providing services and producing and delivering goods in connection with an enterprise fund's principal ongoing operations. The principal operating revenues of the Electric Utility are charges to customers for electric sales and services. Operating expenses for the Electric Utility include the cost of electric sales and services, administrative expenses, and depreciation on capital assets. All revenues and expenses not meeting this definition are reported as non-operating revenues and expenses.

IMPLEMENTATION OF NEW ACCOUNTING PRONOUNCEMENTS

The following Governmental Accounting Standards Board (GASB) pronouncements became effective and were implemented during fiscal year 2024-2025:

GASB Statement No. 101, *Compensated Absences* - This Statement requires that liabilities for compensated absences be recognized for (1) leave that has not been used and (2) leave that has been used but not yet paid in cash or settled through noncash means. It also requires that a liability for certain types of compensated absences—including parental leave, military leave, and jury duty leave—not be recognized until the leave commences. This Statement also requires that a liability for specific types of compensated absences not be recognized until the leave is used. Further, this Statement establishes guidance for measuring a liability for leave that has not been used, generally using an employee's pay rate as of the date of the financial statements.

GASB Statement No. 102, *Certain Risk Disclosures* - This Statement requires a government to assess whether a concentration or constraint makes the primary government reporting unit or other reporting units that report a liability for revenue debt vulnerable to the risk of a substantial impact. Additionally, this Statement requires a government to assess whether an event or events associated with a concentration or constraint that could cause the substantial impact have occurred, have begun to occur, or are more likely than not to begin to occur within 12 months of the date the financial statements are issued. If a government determines that those criteria for disclosure have been met for a concentration or constraint, it should disclose information in notes to financial statements in sufficient detail to enable users of financial statements to understand the nature of the circumstances disclosed and the government's vulnerability to the risk of a substantial impact.

The following GASB pronouncements became effective and were implemented during fiscal year 2023-2024:

GASB Statement No. 99, *Omnibus 2022* - This Statement provides clarification on previously issued Statements, including the classification and reporting of derivative instruments within the scope of Statement No. 53, *Accounting and Financial Reporting for Derivative Instruments*, that do not meet the definition of either an investment derivative instrument or a hedging derivative instrument; clarification of provisions in Statement No. 87, *Leases*, as amended, related to the determination of the lease term, classification of a lease as a short-term lease, recognition and measurement of a lease liability and a lease asset, and identification of lease incentives; clarification of provisions in Statement No. 94, *Public-Private and Public-Public Partnerships and Availability Payment Arrangements*, related to (a) the determination of the public-private and public-public partnership (PPP) term and (b) recognition and measurement of installment payments and the transfer of the underlying PPP asset; clarification of provisions in Statement No. 96, *Subscription-Based Information Technology Arrangements*, related to the subscription-based information technology arrangement (SBITA) term, classification of a SBITA as a short-term SBITA, and recognition and measurement of a subscription liability; extension of the period during which the London Interback Offered Rate (LIBOR) is considered an appropriate benchmark interest rate

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

IMPLEMENTATION OF NEW ACCOUNTING PRONOUNCEMENTS (CONTINUED)

for the qualitative evaluation of the effectiveness of an interest rate swap that hedges the interest rate risk of taxable debt; accounting for the distribution of benefits as part of the Supplemental Nutrition Assistance Program (SNAP); disclosures related to nonmonetary transactions; pledges of future revenues when resources are not received by the pledging government; clarification of provisions in Statement No. 34, *Basic Financial Statements—and Management's Discussion and Analysis—for State and Local Governments*, as amended, related to the focus of the government-wide financial statements; terminology updates related to certain provisions of Statement No. 63, *Financial Reporting of Deferred Outflows of Resources, Deferred Inflows of Resources, and Net Position*; and terminology used in Statement 53 to refer to resource flows statements.

GASB Statement No. 100, *Accounting Changes and Error Corrections* - This Statement defines accounting changes as changes in accounting principles, changes in accounting estimates, and changes to or within the financial reporting entity and describes the transactions or other events that constitute those changes. It prescribes the accounting and financial reporting for (1) each type of accounting change and (2) error corrections, and requires that (a) changes in accounting principles and error corrections be reported retroactively by restating prior periods, (b) changes to or within the financial reporting entity be reported by adjusting beginning balances of the current period, and (c) changes in accounting estimates be reported prospectively by recognizing the change in the current period. Refer to Note 14 for current-year adjustments related to GASB Statement No. 100.

Other Applicable Pronouncements - In November 2016, the GASB issued Statement No. 83, *Certain Asset Retirement Obligations* (GASB 83). This Statement addresses accounting and financial reporting for certain asset retirement obligations (AROs). An ARO is a legally enforceable liability associated with the retirement of a tangible capital asset. This Statement establishes criteria for (1) determining the timing and pattern of liability recognition and a corresponding deferred outflow, (2) requires liability recognition when it is incurred and reasonably estimable, and (3) requires ARO measurement to be based on the best estimate of the current value of outlays expected to be incurred. If an ARO has been incurred but is not yet recognized because it is not reasonably estimable, the government is required to disclose that fact and the reasons therefor. This Statement will enhance comparability of financial statements among governments by establishing uniform criteria for governments to recognize and measure certain AROs, including obligations that may not have been previously reported. This Statement is effective for reporting periods beginning after June 15, 2020.

According to *Clearwater Power Plant Asset Purchase and Sale Agreement* dated March 3, 2010, the City of Riverside purchased the Clearwater Power Plant (the “Plant”) from the City of Corona to own, operate, and pay all costs related to the Plant and the assets, as set forth in the agreement. On August 26, 2010, Temporary Right of Entry Agreement was made and entered into between the City of Riverside (“Riverside”) and the City of Corona (“Corona”) in which Corona leased the Corona Clearwater Cogeneration Facility (the “Property”) to Riverside for its operation and maintenance of the Property. Riverside is responsible for plant decommissioning and site restoration related to the Plant. The ARO evaluation study to measure the obligation was completed in fiscal year 2019-2020. The final long-term agreement is currently under review by the U.S. Army Corps of Engineers and is anticipated to be finalized by the end of fiscal year 2025-2026. Because the final lease agreement has not yet been executed and the useful life of the plant has not been determined, a liability and related deferred outflow will not recorded in fiscal year 2024-2025.

USE OF ESTIMATES

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses during a reporting period. Accordingly, actual results could differ from those estimates.

REVENUE RECOGNITION

The Electric Utility customers are billed monthly. Unbilled electric service charges, including Public Benefit Programs, are recorded at year-end and are included in accounts receivable. Unbilled accounts receivable totaled $29,095 and $17,991 at June 30, 2025 and 2024, respectively.

An allowance for doubtful accounts is maintained for the Electric Utility and miscellaneous accounts receivable. The balance in this account is adjusted at fiscal year-end to approximate the amount anticipated to be uncollectible.

ELECTRIC UTILITY:
NOTES TO THE FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

ELECTRIC UTILITY PLANT AND DEPRECIATION

The Electric Utility defines capital assets as assets with an initial, individual cost of more than ten thousand dollars and an estimated useful life in excess of one year. This capitalization threshold was increased from the prior five-thousand-dollar threshold effective May 2025. Electric Utility plant assets are valued at historical cost or estimated historical cost, if actual historical cost is not available. Costs include labor; materials; allocated indirect charges such as engineering, supervision, construction and transportation equipment; retirement plan contributions and other fringe benefits. Contributed plant assets are recorded at their acquisition values as of the date of contribution. The cost of relatively minor replacements is included in maintenance expense. Intangible assets that cost more than one hundred thousand dollars with useful lives of at least three years are capitalized and are recorded at cost.

Depreciation is provided over the estimated useful lives of the related assets using the straight-line method. The estimated useful lives are as follows:

Production plant	10-40 years
Transmission and distribution plant	20-50 years
General plant and equipment	5-50 years
Intangibles	5-10 years

RESTRICTED ASSETS

Proceeds of revenue bonds yet to be used for capital projects, as well as certain resources set aside for debt service, are classified as restricted assets in the Statements of Net Position because their use is limited by applicable bond covenants. Funds set aside for the nuclear decommissioning and regulatory requirements relating to greenhouse gas allowances are also classified as restricted assets because their use is legally restricted to a specific purpose. Generally, the Electric Utility will first apply restricted resources when expenses are incurred for which both restricted and unrestricted resources are available.

In January 1998, the Electric Utility began collecting a surcharge for Public Benefit Programs on customer utility bills. This surcharge is mandated by state legislation included in Assembly Bill 1890 and is restricted to various socially beneficial programs and services. The programs and services include cost effective demand-side management services to promote energy efficiency and conservation and related education and information; ongoing support and new investments in renewable resource technologies; energy research and development; and programs and services for low-income electric customers. The activity associated with the surcharge for Public Benefit Programs is reflected in the accompanying financial statements on the Statements of Net Position, Statements of Revenues, Expenses and Changes in Net Position, and Statements of Cash Flows.

CASH AND CASH EQUIVALENTS

For the Statements of Cash Flows, cash and cash equivalents include all unrestricted and restricted highly liquid investments with original purchase maturities of three months or less, and all bond construction proceeds available for capital projects held at fiscal agent. Pooled cash and investments in the City's Treasury represent monies in a cash management pool. Such accounts are similar in nature to demand deposits, and are classified as cash equivalents for the purpose of presentation in the Statements of Cash Flows. Further details regarding cash and cash equivalents can be found in Note 2.

CASH AND INVESTMENTS

The Electric Utility's cash and investments, except for funds required to be held by outside fiscal agents under the provisions of bond indentures, which are administered by outside agencies, are invested in the cash and investment pool of the City.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

CASH AND INVESTMENTS (CONTINUED)

The Electric Utility values its cash and investments in accordance with provisions of GASB Statement No. 72, *Fair Value Measurement and Application*, which requires governmental entities to use valuation techniques that are appropriate under the circumstances and for which sufficient data are available to measure fair value. The techniques should be consistent with one or more of the following approaches: the market approach, the cost approach or the income approach. Valuation includes a hierarchy of inputs with three distinct levels. Level 1 are quoted prices in an active market for identical assets; Level 2 inputs are significant other observable inputs; and Level 3 inputs are significant unobservable inputs. The Electric Utility does not value any of its investments using level 3 inputs. Further details regarding cash and investments can be found in Note 2.

City-wide information concerning cash and investments as of June 30, 2025, including authorized investments, fair value measurement and application, custodial credit risk, credit and interest rate risk for debt securities and concentration of investments, carrying amount and market value of deposits and investments can be found in the notes to the City's financial statements in the City's Annual Comprehensive Financial Report.

CASH AND INVESTMENTS AT FISCAL AGENTS

Cash and investments maintained by fiscal agents are considered restricted by the Electric Utility. A portion is pledged as collateral for payment of principal and interest on outstanding bonds and certain funds are set aside to decommission the Electric Utility's proportionate share of Units 2 and 3 at SONGS. Further details regarding the jointly-owned project SONGS can be found in Note 10. Pursuant to certain bond indentures, the fiscal agent establishes, maintains and holds in trust a separate restricted rebatable arbitrage account. The Electric Utility calculates the rebatable arbitrage liability annually and the fiscal agent pays the computed arbitrage rebate to the U.S. Treasury every five years. Further details regarding arbitrage can be found in Note 8. Further details regarding cash and investments at fiscal agents can be found in Note 2.

CalPERS's positive investment returns contributed to the reduction of the unfunded accrued liability (UAL); as a result, originally budgeted UAL payments were redirected to the Electric Utility's restricted cash and investments held at fiscal agent to aid the Electric Utility in long-term management of rising pension costs. See Note 6 for further discussion related to the CalPERS pension plan, including UAL.

DESIGNATED CASH RESERVES

The Riverside Public Utilities Cash Reserve Policy establishes several designated cash reserves in the Electric Utility for strategic purposes. Designated reserves are set aside for specific purposes determined by the Board of Public Utilities and City Council. Designated reserves may be held for capital or operating purposes.

Designated cash reserve balances as of June 30, 2025 and 2024 were as follows: Additional Decommissioning Liability Reserve $12,227 and $10,885, Customer Deposits $6,042 and $5,014, Capital Repair and Replacement Reserve $2,406 and $2,336, Electric Reliability Reserve $95,418 and $95,689, Mission Square Improvement Reserve $3,408 and $2,757, and Dark Fiber Reserve $4,767 and $5,556. The combined total for these reserves was $124,268 and $122,237 at June 30, 2025 and 2024, respectively, and is included as a component of unrestricted cash and cash equivalents in the accompanying Statements of Net Position.

ADVANCES TO OTHER FUNDS OF THE CITY

Advances to Successor Agency Trust Fund have been recorded as a result of agreements between the Electric Utility and the Successor Agency. The balances as of June 30, 2025 and 2024 are $1,098 and $1,555, respectively.

DERIVATIVES

The Electric Utility accounts for derivative instruments using GASB Statement No. 53, *Accounting and Financial Reporting for Derivative Instruments* (GASB 53). This Statement requires the Electric Utility to report its derivative instruments at fair value. Changes in fair value for effective hedges are to be reported as deferred inflows and outflows of resources on the Statements of Net Position. Changes in fair value of derivative instruments not meeting the criteria for an effective hedge, or that are associated with investments are to be reported in the non-operating revenues section of the Statements of Revenues, Expenses and Changes in Net Position.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

DERIVATIVES (CONTINUED)

The Electric Utility has determined that its interest rate swaps associated with variable-rate obligations, which were fully refunded in February 2024, were derivative instruments under GASB 53. See Note 4 for further discussion related to the Electric Utility's interest rate swaps.

Various transactions permitted in the Electric Utility's Power Resources Risk Management Policies may be considered derivatives, including energy and/or gas transactions for swaps, options, forward arrangements and congestion revenue rights (CRR). GASB 53 allows an exception for the Statements of Net Position deferral hedges that meet the normal purchases and normal sales exception. The Electric Utility has determined that all of its contracts including CRRs fall under the scope of "normal purchases and normal sales" and are exempt from GASB 53.

BOND PREMIUMS AND GAINS/LOSSES ON REFUNDING

Bond premiums and gains/losses on refunding (including gains/losses related to interest rate swap transactions) are deferred and amortized over the term of the new bonds using the effective interest method. Bonds payable are reported net of the applicable bond premiums. Gains/losses on refunding are reported as deferred inflows or outflows of resources.

CUSTOMER DEPOSITS

The City holds customer deposits as security for the payment of utility bills and design fee deposits for future construction of electrical facilities. The Electric Utility's portion of these deposits as of June 30, 2025 and 2024 was $12,109 and $11,972, respectively.

COMPENSATED ABSENCES

The accompanying financial statements include accruals for salaries, fringe benefits and compensated absences due to employees at June 30, 2025 and 2024. The Electric Utility treats compensated absences due to employees as an expense and a liability of which a current portion is included in accounts payable and other accruals in the accompanying Statements of Net Position. The amount accrued for compensated absences was $8,975 and $7,400 at June 30, 2025 and 2024, respectively.

Employees receive 10 to 25 vacation days per year based upon length of service. A maximum of two years' vacation accrual may be accumulated, and unused vacation is paid in cash upon separation.

Employees generally receive one day of sick leave for each month of employment with unlimited accumulation. Upon retirement or death, certain employees or their estates receive a percentage of unused sick leave paid in a lump sum based on longevity.

During fiscal year 2024-2025, GASB Statement No. 101, *Compensated Absences* became effective and was implemented. This Statement addresses accounting and financial reporting for certain liabilities for compensated absences. See Note 5 for further information regarding compensated absences.

INSURANCE PROGRAMS

The Electric Utility participates in a self-insurance program for workers' compensation and general liability coverage that is administered by the City. The Electric Utility pays an amount to the City based on actuarial estimates of the amounts needed to fund prior and current year claims and incidents that have been incurred but not reported. The City maintains property insurance on most City property holdings, for a shared limit of $1 billion and $210 million to cover power generation facilities.

City-wide information concerning risks, insurance policy limits and deductibles and designation of general fund balance for risk for the year ended June 30, 2025 may be found in the notes to the City's financial statements in the City's Annual Comprehensive Financial Report.

Although the ultimate amount of losses incurred through June 30, 2025 is dependent upon future developments, management believes that amounts paid to the City are sufficient to cover such losses. Premiums paid to the City by the Electric Utility, including the Public Benefit Programs, were $2,363 and $2,469 for the years ended June 30, 2025 and 2024, respectively. Any losses above the City's reserves would be covered through increased rates charged to the Electric Utility in future years.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

EMPLOYEE RETIREMENT PLAN

The City contributes to the California Public Employees Retirement System (CalPERS), an agent multiple employer public employee defined benefit pension plan. CalPERS provides retirement and disability benefits, annual cost-of-living adjustments, and death benefits to plan members and beneficiaries. CalPERS acts as a common investment and administrative agent for participating public entities within the State of California. Benefit provisions and all other requirements are established by state statute and City ordinance.

For purposes of measuring the net pension asset/liability and deferred outflows/inflows of resources related to pensions and pension expense, information about the fiduciary net position of the City of Riverside California Public Employees' Retirement System plans (Plans) and additions to/deductions from the Plans' fiduciary net position have been determined on the same basis as they are reported by CalPERS. For this purpose, benefit payments (including refunds of employee contributions) are recognized when due and payable in accordance with the benefit terms. Investments are reported at fair value. Further details of employee retirement plan can be found in Note 6.

OTHER POSTEMPLOYMENT BENEFITS (OPEB)

OPEB refers to the benefits, other than pensions, that the City provides as part of an employee's retirement benefits. The net OPEB liability is defined as the liability of employers contributing to employees for benefits provided through a defined benefit OPEB plan that is administered through a trust. Further details for OPEB can be found in Note 7.

DEFERRED OUTFLOWS AND DEFERRED INFLOWS OF RESOURCES

When applicable, the Statements of Net Position will report a separate section for deferred outflows of resources. Deferred outflows of resources represent outflows of resources (consumption of net position) that apply to future periods and that, therefore, will not be recognized as an expense or expenditure until that time. Deferred outflows of resources consist of losses on refunding and deferred outflows related to pension and OPEB, which include pension contributions subsequent to measurement date, difference between actual and actuarial determined contribution, changes in assumptions and net differences between projected and actual earnings on pension plan investments.

Conversely, deferred inflows of resources represent inflows of resources (acquisition of net position) that apply to future periods and that, therefore, are not recognized as an inflow of resources (revenue) until that time. Deferred inflows of resources consist of lease-related items and deferred inflows related to pension and OPEB, which include changes in assumptions, differences between expected and actual experience and net differences between projected and actual earnings on pension plan investments.

REGULATORY ASSETS

In accordance with regulatory accounting criteria set forth in GASB Codification (GASB Statement No. 62), enterprise funds that are used to account for rate-regulated activities are permitted to defer certain expenses and revenues that would otherwise be recognized when incurred, provided that the Electric Utility is recovering or expects to recover or refund such amounts in rates charged to its customers. Accordingly, regulatory assets relating to debt issuance costs have been recognized in the Statements of Net Position.

NET POSITION

The Electric Utility's net position represents the difference between assets and deferred outflows of resources less liabilities and deferred inflows of resources, which is classified into the following three components:

Net investment in capital assets – this component consists of capital assets (net of accumulated depreciation) reduced by the outstanding balances of any bonds or other borrowings that are attributable to the acquisition, construction, or improvement of those assets, excluding unspent bond proceeds.

Restricted – this component represents restricted assets less liabilities and deferred inflows related to those assets. Restricted assets are recorded when there are limitations imposed by creditors (such as through debt covenants), contributors, or laws or regulation of other governments or constraints imposed by law through constitutional provisions or through enabling legislation.

Unrestricted – this component consists of net position that does not meet the definition of "restricted" or "net investment in capital assets."

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

CONTRIBUTIONS TO THE CITY'S GENERAL FUND

Pursuant to the City of Riverside Charter, the Electric Utility may transfer up to 11.5 percent of its prior year's gross operating revenues, including adjustments, to the City's general fund. In fiscal years ended June 30, 2025 and 2024, $45,215 and $45,289, respectively, was transferred, representing 11.5 percent. Additional information can be found in Note 12.

LEASES AND SUBSCRIPTION-BASED INFORMATION TECHNOLOGY ARRANGEMENTS

Leases are defined by the general government as the right to use an underlying asset. As lessee, the Electric Utility recognizes a lease liability and a lease asset at the beginning of a lease period unless the lease is considered a short-term lease or transfers ownership of the underlying asset. Lease assets are measured based on the net present value of the future lease payments at inception, using the weighted average cost of capital, which approximate the incremental borrowing rate. Re-measurement of a lease liability occurs when there is a change in the lease term and/or other changes that are likely to have a significant impact on the lease liability. The Electric Utility calculates the amortization of the discount on the lease liability and report that amount as outflows of resources. Payments are allocated first to accrued interest liability and then to the lease liability. Variable lease payments based on the usage of the underlying assets are not included in the lease liability calculations but are recognized as outflows of resources in the period in which the obligation was incurred. As lessor, the Electric Utility recognizes a lease receivable. The lease receivable is measured using the net present value of future lease payments to be received for the lease term and deferred inflow of receivables at the beginning of the lease term. Periodic amortization of the discount on the receivable are reported as interest revenue for that period. Deferred inflows of resources are recognized as inflows on a straight-line basis over the term of the lease. This recognition does not apply to short-term leases, contracts that transfer ownership, leases of assets that are investments, or certain regulated leases. Any initial direct costs are reported as an outflow of resources for that period. Re-measurement of lease receivables occur when there are modifications, including but not limited to changes in the contract price, lease term, and adding or removing an underlying asset to the lease agreements. In the case of a partial or full lease termination, the carrying value of the lease receivable and the related deferred inflow of resources will be reduced and will include a gain or loss for the difference. For lease contracts that are short-term, the Electric Utility recognizes short-term lease payments as inflows of resources (revenues) based on the payment provisions of the lease contract. Liabilities are only recognized if payments are received in advance, and receivables are only recognized if payments are received subsequent to the reporting period. Additional disclosures regarding regulated leases are in Note 13.

Subscription-Based Information Technology Arrangements (SBITAs) are contracts that convey control of the right to use another party's IT software, alone or in combination with tangible capital assets, as specified in the contract for a period of time in an exchange or exchange-like transaction. To determine whether a contract conveys control of the right to use the underlying IT assets, the City assesses both the right to obtain the present service capacity from use of the underlying IT assets and the right to determine the nature and manner of use of the underlying IT assets as specified in the contract. Contracts that solely provide IT support services are excluded from the definition of a SBITA. The subscription term is the period during which the City has a noncancellable right to use the underlying IT assets, plus the periods covered by the City's option to extend the SBITA if it is reasonably certain, based on all relevant factors, that the government will exercise that option. Periods for which both the government and the SBITA vendor have an option to terminate the SBITA without permission from the other party (or if both parties have to agree to extend) are cancellable periods and are excluded from the subscription term. Additional disclosures regarding SBITAs are in Note 13.

BUDGET AND BUDGETARY ACCOUNTING

The Electric Utility presents, and the City Council adopts, a biennial budget. The proposed budget includes estimated expenses and forecasted revenues. The City Council generally adopts the Electric Utility's budget in June biennially via resolution.

RECLASSIFICATIONS/RESTATEMENTS

During fiscal year 2025, certain restatements were made to correct errors identified in prior-year financial statements. All error corrections were recorded as adjustments to the beginning net position of fiscal year 2024. Additional information is provided in Note 14.

2. CASH AND INVESTMENTS

Cash and investments at June 30, 2025 and 2024, consist of the following (in thousands):

	June 30, 2025	June 30, 2024
	Fair Value	
Equity interest in City Treasurer's investment pool	$ 375,204	$ 348,474
Cash and investments at fiscal agent	48,258	48,530
Cash and cash equivalents at fiscal agent	97,958	127,743
Total cash, cash equivalents and investments	$ 521,420	$ 524,747

The amounts above are reflected in the accompanying financial statements as:

	June 30, 2025	June 30, 2024
Unrestricted cash and cash equivalents	$ 276,817	$ 258,200
Restricted cash and cash equivalents	63,677	58,241
Restricted Public Benefits - cash and cash equivalents	34,710	32,033
Restricted cash and investments at fiscal agent	48,258	48,530
Restricted cash and cash equivalents at fiscal agent	97,958	127,743
Total cash, cash equivalents and investments	$ 521,420	$ 524,747

The investment types in the tables below related to the Electric Utility's investments in the City Treasurer's investment pool represent the Electric Utility's prorated share of the investment types in the investment pool and do not represent ownership interests in the individual investments.

ELECTRIC UTILITY:
NOTES TO THE FINANCIAL STATEMENTS

2. CASH AND INVESTMENTS (CONTINUED)

The Electric Utility categorizes its fair value measurements within the fair value hierarchy established by generally accepted accounting principles. The Electric Utility has the following recurring fair value measurements as of June 30, 2025 and 2024:

Investment Type	June 30, 2025 Fair Value	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Investments not Subject to Fair Value Hierarchy
Held by fiscal agent					
Money market funds	$ 105,955	$ -	$ -	$ -	$ 105,955
Asset-backed securities	932	-	932	-	-
US Treasury notes/bonds	26,264	-	26,264	-	-
Federal agency obligations	1,688	-	1,688	-	-
Medium-term corporate notes	7,789	-	7,789	-	-
Supranational securities	3,588	-	3,588	-	-
City Treasurer's investment pool[1]					
Money market funds	1,819	-	-	-	1,819
Joint powers authority pools	46,783	-	-	-	46,783
Mortgage pass-through securities	14,375	-	14,375	-	-
Asset-backed securities	43,832	-	43,832	-	-
US Treasury obligations	151,814	-	151,814	-	-
Federal agency obligations	12,928	-	12,928	-	-
Medium-term corporate notes	76,399	-	76,399	-	-
Supranational securities	27,254	-	27,254	-	-
Total	$ 521,420	$ -	$ 366,863	$ -	$ 154,557

Investment Type	June 30, 2024 Fair Value	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Investments not Subject to Fair Value Hierarchy
Held by fiscal agent					
Money market funds	$ 131,623	$ -	$ -	$ -	$ 131,623
Asset-backed securities	1,988	-	1,988	-	-
US Treasury notes/bonds	24,657	-	24,657	-	-
Federal agency obligations	3,439	-	3,439	-	-
Corp medium term notes	10,715	-	10,715	-	-
Supranational securities	3,851	-	3,851	-	-
City Treasurer's investment pool[1]					
Money market funds	333	-	-	-	333
Joint powers authority pools	71,024	-	-	-	71,024
Mortgage pass-through securities	10,453	-	10,453	-	-
Asset backed securities	30,250	-	30,250	-	-
US Treasury obligations	113,513	-	113,513	-	-
Federal agency obligations	32,221	-	32,221	-	-
Medium-term corporate notes	69,588	-	69,588	-	-
Supranational securities	21,092	-	21,092	-	-
Total	$ 524,747	$ -	$ 321,767	$ -	$ 202,980

[1]Additional information on investment types, fair value measurement, interest rate risk and credit risk may be found in the notes to the City's financial statements in the City's Annual Comprehensive Financial Report.

2. CASH AND INVESTMENTS (CONTINUED)

Cash and investments distribution by maturities as of June 30, 2025 and 2024 are as follows:

Investment Type	June 30, 2025 Fair Value	Remaining Maturity (in Months) 12 Months or Less	13 to 36 Months	37 to 60 Months	More than 60 Months
Held by fiscal agent					
Money market funds	$ 105,955	$ 105,955	$ -	$ -	$ -
Asset-backed securities	932	15	473	444	-
US Treasury notes/bonds	26,264	10,284	6,809	9,171	-
Federal agency obligations	1,688	1,251	-	437	-
Medium-term corporate notes	7,789	748	1,094	5,947	-
Supranational securities	3,588	2,006	-	1,582	-
City Treasurer's investment pool[1]					
Money market funds	1,819	1,819	-	-	-
Joint powers authority pools	46,783	46,783	-	-	-
Mortgage pass-through securities	14,375	83	6,596	7,696	-
Asset-backed securities	43,832	1,543	13,748	28,541	-
US Treasury obligations	151,814	-	56,162	95,652	-
Federal agency obligations	12,928	2,878	10,050	-	-
Medium-term corporate notes	76,399	11,227	32,085	33,087	-
Supranational securities	27,254	5,253	-	22,001	-
Total	$ 521,420	$ 189,845	$ 127,017	$ 204,558	$ -

Investment Type	June 30, 2024 Fair Value	Remaining Maturity (in Months) 12 Months or Less	13 to 36 Months	37 to 60 Months	More than 60 Months
Held by fiscal agent					
Money market funds	$ 131,623	$ 131,623	$ -	$ -	$ -
Asset-backed securities	1,988	-	1,344	644	-
US Treasury notes/bonds	24,657	1,485	12,609	10,563	-
Federal agency obligations	3,439	2,196	1,243	-	-
Corp medium term notes	10,715	3,415	3,588	3,712	-
Supranational securities	3,851	988	1,916	947	-
City Treasurer's investment pool[1]					
Money market funds	333	333	-	-	-
Joint powers authority pools	71,024	71,024	-	-	-
Mortgage pass-through securities	10,453	3,191	1,496	5,766	-
Asset backed securities	30,250	1,697	10,333	18,220	-
US Treasury obligations	113,513	-	35,615	77,898	-
Federal agency obligations	32,221	9,917	13,467	8,837	-
Medium-term corporate notes	69,588	10,622	30,661	28,305	-
Supranational securities	21,092	1,379	7,655	12,058	-
Total	$ 524,747	$ 237,870	$ 119,927	$ 166,950	$ -

[1] Additional information on investment types, fair value measurement, interest rate risk and credit risk may be found in the notes to the City's financial statements in the City's Annual Comprehensive Financial Report.

2. CASH AND INVESTMENTS (CONTINUED)

Presented below is the actual rating as of June 30, 2025 and 2024 for each investment type:

Investment Type	June 30, 2025 Fair Value	Ratings as of Year End AAA	AA	A	Unrated
Held by fiscal agent					
Money market funds	$ 105,955	$ 1,276	$ -	$ -	$ 104,679
Asset-backed securities	932	472	-	-	460
US Treasury notes/bonds	26,264	-	26,264	-	-
Federal agency obligations	1,688	437	1,251	-	-
Medium-term corporate notes	7,789	-	1,881	3,540	2,368
Supranational securities	3,588	-	-	-	3,588
City Treasurer's investment pool[1]					
Money market funds	1,819	1,819	-	-	-
Joint powers authority pools	46,783	46,783	-	-	-
Mortgage pass-through securities	14,375	11,429	2,946	-	-
Asset-backed securities	43,832	31,285	-	-	12,547
US Treasury obligations	151,814	-	151,814	-	-
Federal agency obligations	12,928	-	12,928	-	-
Medium-term corporate notes	76,399	2,371	22,008	35,755	16,265
Supranational securities	27,254	-	-	-	27,254
Total	$ 521,420	$ 95,872	$ 219,092	$ 39,295	$ 167,161

Investment Type	June 30, 2024 Fair Value	Ratings as of Year End AAA	AA	A	Unrated
Held by fiscal agent					
Money market funds	$ 131,623	$ 359	$ -	$ -	$ 131,264
Asset-backed securities	1,988	949	-	-	1,039
US Treasury notes/bonds	24,657	-	24,657	-	-
Federal agency obligations	3,439	-	3,439	-	-
Corp medium term notes	10,715	-	2,502	5,726	2,487
Supranational securities	3,851	-	-	-	3,851
City Treasurer's investment pool[1]					
Money market funds	333	333	-	-	-
Joint powers authority pools	71,024	71,024	-	-	-
Morgage pass-through securities	10,453	9,483	970	-	-
Asset backed securities	30,250	23,188	-	-	7,062
US Treasury obligations	113,513	-	113,513	-	-
Federal agency obligations	32,221	-	32,221	-	-
Medium-term corporate notes	69,588	2,107	21,435	34,151	11,895
Supranational securities	21,092	-	-	-	21,092
Total	$ 524,747	$ 107,443	$ 198,737	$ 39,877	$ 178,690

[1] Additional information on investment types, fair value measurement, interest rate risk and credit risk may be found in the notes to the City's financial statements in the City's Annual Comprehensive Financial Report.

ELECTRIC UTILITY:
NOTES TO THE FINANCIAL STATEMENTS

3. CAPITAL ASSETS

The following is a summary of changes in utility plant and lease and subscription assets during the fiscal years ended June 30, 2025 and 2024:

	Balance As of 6/30/2023	Restatement**	Additions	Retirements/ Transfers	Balance As of 6/30/2024*	Additions	Retirements/ Transfers	Balance As of 6/30/2025
Production	$ 265,966	$ -	$ -	$ -	$ 265,966	$ 3,440	$ (2,125)	$ 267,281
Transmission	53,416	-	174	-	53,590	8,286	-	61,876
Distribution	741,877	-	13,294	(2,576)	752,595	45,126	(1,450)	796,271
General	122,127	-	3,119	(546)	124,700	5,836	(2,467)	128,069
Intangibles	26,667	-	610	-	27,277	-	-	27,277
Depreciable utility plant	1,210,053	-	17,197	(3,122)	1,224,128	62,688	(6,042)	1,280,774
Less accumulated depreciation:								
Production	(129,553)	-	(8,919)	-	(138,472)	(8,905)	2,124	(145,253)
Transmission	(23,377)	(124)	(1,057)	-	(24,558)	(1,386)	-	(25,944)
Distribution	(333,774)	(437)	(20,353)	1,986	(352,578)	(20,785)	786	(372,577)
General	(59,097)	(31)	(4,846)	546	(63,428)	(5,445)	2,467	(66,406)
Intangibles	(18,635)	-	(2,906)	-	(21,541)	(2,850)	-	(24,391)
Accumulated depreciation	(564,436)	(592)	(38,081)	2,532	(600,577)	(39,371)	5,377	(634,571)
Net depreciable utility plant	645,617	(592)	(20,884)	(590)	623,551	23,317	(665)	646,203
Land	56,386	-	52	(2)	56,436	93	-	56,529
Intangible, non-amortizable	10,651	-	-	-	10,651	-	-	10,651
Construction in progress	72,262	(690)	27,366	(14,395)	84,543	58,795	(59,918)	83,420
Nondepreciable utility plant	139,299	(690)	27,418	(14,397)	151,630	58,888	(59,918)	150,600
Total utility plant	$ 784,916	$ (1,282)	$ 6,534	$ (14,987)	$ 775,181	$ 82,205	$ (60,583)	$ 796,803
Lease and subscription assets, being amortized:								
Land	$ -	$ -	$ -	$ -	$ -	$ 473	$ -	$ 473
Building - intangible	348	-	-	-	348	-	-	348
Machinery and equipment - intangible	280	-	123	(138)	265	44	(11)	298
Subscription-based information technology arrangements	93	-	138	-	231	-	(96)	135
Total lease and subscription assets	721	-	261	(138)	844	517	(107)	1,254
Less lease accumulated amortization:								
Land - right to use	-	-	-	-	-	(55)	-	(55)
Machinery and equipment - intangible	(124)	-	(61)	(82)	(103)	(62)	(11)	(154)
Building - intangible	(149)	-	(74)	-	(223)	(74)	-	(297)
Subscription-based information technology arrangements	(43)	-	(65)	-	(108)	(69)	96	(81)
Total lease accumulated amortization	(316)	-	(200)	82	(434)	(260)	107	(587)
Total lease and subscription assets, net	$ 405	$ -	$ 61	$ (56)	$ 410	$ 257	$ -	$ 667
Total capital assets being depreciated, net	**$ 785,321**	**$ (1,282)**	**$ 6,595**	**$ (15,043)**	**$ 775,591**	**$ 82,462**	**$ (60,583)**	**$ 797,470**

** As restated.*
*** Restatement reflects adjustments to beginning net position for prior-period capital asset corrections identified during FY 2024–25. These adjustments include capitalization of assets previously placed into service with the related accumulated depreciation, and the reclassification of certain long-standing Construction in Progress balances that did not meet capitalization criteria. These corrections were recorded to properly state beginning net position. For further detail refer to Note-14 Restatement of Beginning Net Position.*

4. LONG-TERM OBLIGATIONS

The following is a summary of changes in long-term obligations during the fiscal years ended June 30, 2025 and 2024 (in thousands):

	Balance As of 6/30/2023	Additions	Reductions	Balance As of 6/30/2024	Additions	Reductions	Balance As of 6/30/2025	Due Within One Year
Revenue bonds	$ 549,827	$ 283,940	$ (156,272)	$ 677,495	$ -	$ (22,103)	$ 655,392	$ 18,475
Arbitrage liability	-	-	-	-	2,527	-	2,527	-
Pension obligation bonds	63,408	-	(5,117)	58,291	-	(5,675)	52,616	5,839
Total long-term obligations	$ 613,235	$ 283,940	$ (161,389)	$ 735,786	$ 2,527	$ (27,778)	$ 710,535	$ 24,314

Long-term debt consists of the following (in thousands):

Pension Obligation Bonds Payable

	June 30, 2025	June 30, 2024
$31,960 2017 Taxable Pension Obligation Bonds Series A: fixed rate bonds issued by the City due in annual installments from $2,910 to $3,580 through June 2027, with coupons from 1.3 to 3.1 percent. The Electric Utility's proportional share of the outstanding debt is 29.6 percent.	$ 2,091	$ 3,091
$201,080 2020 Taxable Pension Obligation Bonds Series A (Miscellaneous): fixed rate bonds issued by the City due in annual installments from $1,285 to $14,625 through June 2045, with coupons from 1.7 to 3.9 percent. The Electric Utility's proportional share of the outstanding debt is 32.9 percent.	50,525	55,200
Total pension obligation bonds payable	52,616	58,291

Revenue Bonds Payable

	June 30, 2025	June 30, 2024
$133,290 2010 Electric Revenue Series A Bonds: fixed rate, federally taxable Build America Bonds due in annual principal installments from $2,300 to $33,725 through October 1, 2040, interest of 6.0 to 7.6 percent, excluding 33% sequestration credit from the IRS, effective October 1, 2020.	$ 120,805	$ 123,515
$283,325 2019 Electric Revenue Refunding Series A Bonds: fixed rate bonds due in annual principal installments from $3,545 to $24,005 through October 1, 2048, interest of 5.0 percent.	218,635	232,480
$31,390 2023 Electric Revenue Refunding Series A Bonds: fixed rate bonds due in annual principal installments from $990 to $2,395 through October 1, 2043, interest of 5.0 percent.	30,400	31,390
$213,295 2024 Electric Revenue Refunding Series A Bonds: fixed rate bonds due in annual principal installments from $460 to $12,845 through October 1, 2049, interest of 5.0 percent.	212,835	213,295
Total electric revenue bonds payable	582,675	600,680
Total electric revenue and pension obligation bonds payable	635,291	658,971
Unamortized bond premium	72,717	76,815
Total electric revenue and pension obligation bonds payable, including bond premium	708,008	735,786
Less current portion of revenue and pension obligation bonds payable	(24,314)	(23,680)
Total long-term electric revenue and pension obligation bonds payable	$ 683,694	$ 712,106

4. LONG-TERM OBLIGATIONS (CONTINUED)

Pension Obligation Bonds - The Electric Utility is obligated to pay its share of the City's pension obligation bonds, which the City issued in 2005 and refinanced a portion in May 2017.

In fiscal year ended June 30, 2020, the City issued $432,165 2020 Taxable Pension Obligation Bonds Series A. The bonds were issued to reduce the City's unfunded pension liability in both the City's Miscellaneous and Safety CalPERS plans. It is estimated the issuance will save the City's General Fund approximately $178.5 million throughout the life of the bonds. The fixed rate bonds issued by the City under the miscellaneous plan are due in annual installments from $1,285 to $14,625 through June 2043, with coupons from 1.7% to 3.9%. The Electric Utility's proportional share of the miscellaneous plan is 32.9%.

The Electric Utility's proportional share of the outstanding principal amount of both pension obligation bonds was $52,616 and $58,291 as of June 30, 2025 and 2024, respectively. The bond proceeds were deposited with CalPERS to fund the unfunded actuarial accrued liability for non-safety employees. For more discussion relating to the City's pension obligation bond issuance, see the notes to the City's financial statements in the City's Annual Comprehensive Financial Report for the fiscal year ended June 30, 2025.

Remaining pension obligation bond debt service payments will be made from revenues of the Electric Fund.

As of June 30, 2025, the annual debt service requirements to maturity are as follows (in thousands):

Fiscal Year	Principal	Interest	Total
2026	$ 5,839	$ 1,797	$ 7,636
2027	5,596	1,646	7,242
2028	3,800	1,493	5,293
2029	3,027	1,388	4,415
2030	2,284	1,303	3,587
2031-2035	14,839	5,119	19,958
2036-2040	13,925	2,148	16,073
2041-2043	3,306	194	3,500
Total	$ 52,616	$ 15,088	$ 67,704

As of June 30, 2024, the annual debt service requirements to maturity were as follows (in thousands):

Fiscal Year	Principal	Interest	Total
2025	$ 5,675	$ 1,930	$ 7,605
2026	5,839	1,797	7,636
2027	5,596	1,646	7,242
2028	3,800	1,493	5,293
2029	3,027	1,388	4,415
2030-2034	13,898	5,632	19,530
2035-2039	14,887	2,722	17,609
2040-2043	5,569	410	5,979
Total	$ 58,291	$ 17,018	$ 75,309

Revenue Bonds - All electric revenue bonds are covenanted per the Amended and Restated Resolution No. 17662 (Electric) Master Resolution that upon the occurrence and continuation of an event of default, the owners of 25% in aggregate amount of Bond Obligation may, by written notice to the City, declare the entire unpaid principal and accreted value of the bonds due and payable should the City fail to pay its debts as they become due or upon the entry of any decree or order of bankruptcy of the City.

The Tax Reform Act of 1986 (the Act) requires the Electric Utility to calculate and remit rebatable arbitrage earnings to the Internal Revenue Service. Certain debt and interest earnings on the proceeds of the Electric Utility are subject to the requirements of the Act, which contain yield restrictions on investment of proceeds from tax-exempt financing in higher-yielding taxable securities. The balance in the arbitrage liability as of June 30, 2025 was $2,527 and is included in long-term obligations, less current portion, in the accompanying Statements of Net Position.

4. LONG-TERM OBLIGATIONS (CONTINUED)

$31,390 Electric Revenue Refunding Bonds Series A. The bonds were issued in December 2023 to refund all of the outstanding 2013A Electric Revenue Bonds. Interest on the bonds is 5%, payable April and October of each year. Principal payments are due in annual installments through October 1, 2043, and range from $990 to $2,395.

$213,295 Electric Revenue Bonds Series A. The bonds were issued in February 2024 to fund short-term and long-term capital projects, to refund the outstanding Electric Bonds Series 2008A, 2008C, and 2011A, and pay termination costs associated with certain interest rate swap agreements. Interest on the bonds is 5%, payable in April and October of each year. Principal payments are due in annual installments through October 1, 2049, and range from $460 to $12,845.

Remaining revenue bond debt service payments will be made from revenues of the Electric Fund.

As of June 30, 2025, the annual debt service requirements to maturity are as follows (in thousands):

Fiscal Year	Principal	Interest	Total
2026	$ 18,475	$ 28,763	$ 47,238
2027	19,360	27,822	47,182
2028	20,320	26,830	47,150
2029	23,857	25,789	49,646
2030	22,405	24,695	47,100
2031-2035	135,625	104,147	239,772
2036-2040	171,650	66,554	238,204
2041-2045	100,965	27,809	128,774
2046-2050	72,545	8,873	81,418
Premium	72,717	-	72,717
Total	$ 657,919	$ 341,282	$ 999,201

As of June 30, 2024, the annual debt service requirements to maturity were as follows (in thousands):

Fiscal Year	Principal	Interest	Total
2025	$ 18,005	$ 31,946	$ 49,951
2026	18,475	28,763	47,238
2027	19,360	27,822	47,182
2028	20,320	26,830	47,150
2029	21,330	25,789	47,119
2030-2034	129,835	110,797	240,632
2035-2039	158,065	74,832	232,897
2040-2044	129,245	33,611	162,856
2045-2050	86,045	12,837	98,882
Premium	76,815	-	76,815
Total	$ 677,495	$ 373,227	$ 1,050,722

Pledged Revenue - The Electric Utility has a number of debt issuances (revenue bonds) outstanding that are collateralized by the pledging of electric revenues. The amount and term of the remainder of these commitments are indicated in the revenue bonds payable and annual debt service requirements to maturity tables presented within this Note 4. The purpose of the debt issuances was for the financing of various Electric Utility capital improvement projects.

4. LONG-TERM OBLIGATIONS (CONTINUED)

For June 30, 2025 and 2024, debt service payments as a percentage of the pledged gross revenue, net of certain expenses where so required by the debt agreement, are indicated in the table below. The debt service coverage ratios also approximate the relationship of the debt service to pledged revenue for the remainder of the term of the commitment.

Fiscal Year Ended	Description of Pledged Revenues	Annual Amount of Pledged Revenue (net of expenses) [1, 2, 3, 4]	Annual Debt Service Payments	Debt Service Coverage Ratio
June 30, 2025	Electric revenues	$ 175,782	$ 54,997	3.20
June 30, 2024	Electric revenues	$ 116,861	$ 50,694	2.31

[1]Excludes GASB 68 *Accounting and Financial Reporting for Pension* non-cash adjustments of $9,584 and $7,707 for June 30, 2025 and 2024, respectively.

[2]Excludes GASB 75 *Accounting and Financial Reporting for Postemployment Benefits Other Than Pensions* non-cash adjustments of $526 and $474 for June 30, 2025 and 2024, respectively.

[3]Includes GASB 87 *Leases* net revenue adjustment of $373 and $304 for June 30, 2025 and 2024, respectively.

[4]Includes rebatable arbitrage of $2,527 for June 30, 2025.

LINE OF CREDIT

On February 1, 2019, the City entered into a subordinate line of credit agreement with U.S. Bank, National Association. The agreement was renewed on June 2, 2025. The Subordinate Line of Credit is a tool approved through the Electric and Water Utility Five-Year Rate Plan to manage rate increases by enabling the Electric Utility to reduce cash levels while maintaining compliance with the Riverside Public Utilities Cash Reserve Policy. Under the terms and conditions of the agreement, the City may borrow up to $35,000 for purposes of the capital or operating financial needs of the Electric System. There were no borrowings against the line as of June 30, 2025 and 2024.

LETTERS OF CREDIT

As of June 30, 2024, the Electric Utility's 2008 Electric Revenue Bonds (Series A and C) and 2011 Electric Revenue Bonds (Series A) were fully refunded in February 2024 with the 2024A Electric Revenue Bonds, which are fixed rate bonds and no longer require letters of credit.

Until the refunding in February 2024, the Electric Utility's 2008 Electric Revenue Bonds (Series A and C) and 2011 Electric Revenue Bonds (Series A) required an additional layer of security between the Electric Utility and the purchaser of the bonds. The Electric Utility entered into the following three letters of credit (LOC) to provide liquidity should all or a portion of the debt be optionally tendered to the remarketer without being successfully remarketed:

Debt Issue	LOC Provider	LOC Expiration Date	Annual Commitment Fee
2008 Electric Refunding/Revenue Bonds Series A	Barclays Bank, PLC	2024	0.395%
2008 Electric Refunding/Revenue Bonds Series C	Barclays Bank, PLC	2024	0.395%
2011 Electric Refunding/Revenue Bonds Series A	Bank of America, N.A.	2026	0.350%

To the extent that remarketing proceeds were insufficient or not available, tendered amounts would have been paid from drawings made under an irrevocable direct-pay letter of credit.

Liquidity advances drawn against the LOCs that were not repaid would have been converted to an installment loan with the principal to be paid quarterly not to exceed a 5-year period for the 2008A and 2008C bonds not to exceed a 3-year period for the 2011A bonds. The various indentures allowed the Electric Utility to convert the mode of the debt in the case of a failed remarketing.

For the 2008A and 2008C Bonds, the Electric Utility would have been required to pay annual interest equal to the Base Rate plus 2%, where the Base Rate was the highest of 8%, the Prime Rate plus 2.5%, the Federal Funds Rate plus 2.5% and 1.50% of the yield on the 30-year U.S. Treasury Bond.

For the 2011A Bonds, the Electric Utility would have been required to pay annual interest equal to the Base Rate plus 2%, where the Base Rate is the highest of 10.5%, the Prime Rate plus 1% and the Federal Funds Rate plus 2%.

No amounts had ever been drawn against the three LOCs due to a failed remarketing.

4. LONG-TERM OBLIGATIONS (CONTINUED)

INTEREST RATE SWAPS ON REVENUE BONDS

As of February 1, 2024, the Electric Utility no longer has any cash flow hedging derivative instruments, which are pay-fixed swaps. The 2008 Electric Refunding/Revenue Bonds (Series A and C) and the 2011 Electric Revenue Bonds (Series A) were fully refunded in February with the 2024A Electric Revenue Bonds. These swaps were employed as a hedge against debt that was refunded in 2008 and 2011. At the time of the refunding, hedge accounting ceased to be applied. The balance of the deferral account for each swap was included as part of the deferred loss on refunding associated with the new bonds. The swaps were also employed as a hedge against the new debt. Hedge accounting was applied to that portion of the hedging relationship, which was determined to be effective. The negative fair value of the interest rate swaps related to the new hedging relationship was recorded and deferred on the Statements of Net Position.

Until the refunding in February 2024, the Electric Utility had three cash flow hedging derivative instruments, which were pay-fixed swaps. These swaps were employed as a hedge against debt that was refunded in 2008 and 2011. At the time of the refunding, hedge accounting ceased to be applied. The balance of the deferral account for each swap was included as part of the deferred loss on refunding associated with the new bonds. The swaps were also employed as a hedge against the new debt. Hedge accounting was applied to that portion of the hedging relationship, which was determined to be effective.

Objective: In order to lower borrowing costs as compared to fixed-rate bonds, the Electric Utility entered into interest rate swap agreements in connection with its $141,840 2008 Electric Refunding/Revenue Bonds (Series A and C) and $56,450 2011 (Series A).

Terms: Per the swap agreements, the Electric Utility paid the counterparty a fixed payment and received a variable payment computed as 62.68% of the London Interbank Offering Rate ("LIBOR") one month index plus 12 basis points.

The Electric Refunding/Revenue 2008 (Series A) Bonds' and the related swap agreements' term to maturity was October 1, 2029 and the 2008 (Series C) and 2011 (Series A) Bonds' term to maturity was October 1, 2035.

Replacement of LIBOR: As of July 1, 2023, LIBOR was no longer an appropriate benchmark interest rate for a derivative instrument that hedges the interest risk for taxable debt for purposes of GASB Statement 53. The Secured Overnight Financing Rate (SOFR) was used as the fallback replacement rate.

5. COMPENSATED ABSENCES

A liability for compensated absences is recognized as leave is earned and unused, to the extent that the leave is available for use by the employee in future periods. The liability reflects the amount expected to be settled through paid time-off or payment upon separation, and is measured using pay rates in effect at year-end.

The Electric Utility implemented GASB Statement No. 101, *Compensated Absences* for the fiscal year ended June 30, 2025.

Below is a summary of changes in compensated absences for the Electric Utility as of June 30, 2025 and 2024:

	Balance As of 6/30/2023	Net Increase/ (Decrease)*	Balance As of 6/30/2024	Net Increase/ (Decrease)	Balance As of 6/30/2025	Due Within One Year
Compensated absences	$ 7,478	$ (78)	$ 7,400	$ 1,575	$ 8,975	$ 4,592

**Prior-year amounts have been reclassified to conform to the current year presentation.*

ELECTRIC UTILITY:
NOTES TO THE FINANCIAL STATEMENTS

6. EMPLOYEE RETIREMENT PLAN

PLAN DESCRIPTION

The Electric Utility's employees participate in the City's Miscellaneous (non-safety) Plan (the Plan), an agent multiple employer public employee defined benefit pension plan. CalPERS provides retirement and disability benefits, annual cost-of-living adjustments, and death benefits to plan members and beneficiaries. CalPERS acts as a common investment and administrative agent for participating public entities within the State of California. CalPERS issues a publicly available financial report that includes financial statements and required supplementary information for the cost sharing plans that are administered by CalPERS. Benefit provisions and all other requirements are established by state statute and City ordinance. A copy of CalPERS' annual financial report may be obtained online at www.calpers.ca.gov.

FUNDING POLICY

The City has contributed at the actuarially determined rate provided by CalPERS' actuaries. Participants are required to contribute 8% of their annual covered salary. The City has a multiple tier retirement plan with benefits varying by plan. All permanent full-time and selected part-time employees are eligible for participation in CalPERS. Benefits vest after five years of service and are determined by a formula that considers the employee's age, years of service and salary. Under the Plan, the City pays the employees' contribution to CalPERS for employees hired on or before specific dates as follows:

- 1st Tier –
    - Unrepresented - The retirement formula is 2.7% at age 55 for employees hired on or before October 18, 2011. Unrepresented employees (Sr. Management, Management, Professional, Para-professional, Supervisory, Confidential, and Executive units, excluding the Chief of Police and the Fire Chief) are required to contribute 8% of their pensionable income.
    - SEIU - The retirement formula is 2.7% at age 55 for SEIU and SEIU Refuse employees hired before June 7, 2011. Employees are required to contribute 8% of their pensionable income.
    - IBEW - The retirement formula is 2.7% at age 55 for IBEW and IBEW Supervisory employees hired on or before October 18, 2011. Employees are required to contribute 8% of their pensionable income.
- 2nd Tier – The retirement formula is 2.7% at age 55, and:
    - Miscellaneous employees, IBEW, and IBEW Supervisory hired on or after October 19, 2011 pay their share (8%) of contributions.
    - SEIU and SEIU Refuse employees hired on or after June 7, 2011 pay their share (8%) of contributions.
- 3rd Tier – The retirement formula is 2% at age 62 for new members hired on or after January 1, 2013 and the employee must pay the normal cost to CalPERS, which is currently at 8.25%. Classic members (CalPERS members prior to 12/31/12) hired on or after January 1, 2013 may be placed in a different tier.

The contribution requirements of plan members and the City are established and may be amended by CalPERS.

6. EMPLOYEE RETIREMENT PLAN (CONTINUED)

BENEFITS PROVIDED

CalPERS provides service retirement and disability benefits, annual cost-of-living adjustments and death benefits to plan members who must be public employees and beneficiaries. Benefits are based on years of credited service, equal to one year of full-time employment. Members with five years of total service are eligible to retire at age 50 with statutorily reduced benefits. All members are eligible for non-duty disability benefits after five years of service. The death benefit is one of the following: the Basic Death Benefit, the 1959 Survivor Benefit Level III, or the Optional Settlement 2W Death Benefit. The cost-of-living adjustments for the Plan are applied as specified by the Public Employees' Retirement Law.

CONTRIBUTIONS

Section 20814(c) of the California Public Employees' Retirement Law requires that the employer contribution rates for all public employers be determined on an annual basis by the actuary and shall be effective on the July 1 following notice of a change in the rate. Funding contributions for the Plan is determined annually on an actuarial basis as of June 30 by CalPERS. The actuarially determined rate is the estimated amount necessary to finance the costs of benefits earned by employees during the year, with an additional amount to finance any unfunded accrued liability. The City is required to contribute the difference between the actuarially determined rate and the contribution rate of employees.

NET PENSION LIABILITY

The City's net pension liability for the Plan is measured as the total pension liability, less the pension plan's fiduciary net position. For fiscal year ended June 30, 2025, the net pension liability of the Plan is measured as of 2024, using an annual actuarial valuation as of June 30, 2023 rolled forward to 2024 using standard update procedures. For fiscal year ended 2024, the net pension liability of the Plan is measured as of June 30, 2023, using an annual actuarial valuation as of June 30, 2022 rolled forward to June 30, 2023 using standard update procedures.

A summary of principal assumptions and methods used to determine the net pension liability is shown below:

ACTUARIAL ASSUMPTIONS

The total pension liabilities in the 2024 and 2023 actuarial valuations were determined using the following actuarial assumptions:

	Miscellaneous - Current Year	Miscellaneous - Prior Year
Valuation Date	June 30, 2023	June 30, 2022
Measurement Date	June 30, 2024	June 30, 2023
Actuarial Cost Method	Entry-Age Normal Cost Method	Entry-Age Normal Cost Method
Actuarial Assumptions		
Discount Rate	6.90%	6.90%
Inflation	2.30%	2.30%
Salary Increase	Varies by entry age and service	Varies by entry age and service
Mortality Rate Table[1]	Derived using CalPERS' membership data for all funds.	
Post Retirement Benefit Increase	The lesser of contract COLA or 2.30% until Purchasing Power Protection Allowance floor on purchasing power applies, 2.30% thereafter	The lesser of contract COLA or 2.30% until Purchasing Power Protection Allowance floor on purchasing power applies, 2.30% thereafter

[1]The mortality table used was developed based on CalPERS-specific data. The probabilities of mortality are based on the 2021 CalPERS Experience Study for the period from 2001 to 2019. Pre-retirement and Post-retirement mortality rates include generational mortality improvement using 80% of Scale MP-2020 published by the Society of Actuaries. For more details on this table, please refer to the CalPERS Experience Study and Review of Actuarial Assumptions report from November 2021 that can be found on the CalPERS website.

6. EMPLOYEE RETIREMENT PLAN (CONTINUED)

LONG-TERM EXPECTED RATE OF RETURN

The long-term expected rate of return on pension plan investments was determined using a building-block method in expected future real rates of return (expected returns, net of pension plan investment expense and inflation) are developed for each major asset class. In determining the long-term expected rate of return, CalPERS took into account both short-term and long-term market return expectations. Using historical returns of all of the funds' asset classes, expected compound (geometric) returns were calculated over the next 20 years using a buildingblock approach. The expected rate of return was then adjusted to account for assumed administrative expenses of 10 Basis points. The expected real rates of return by asset class are as follows:

Measurement Date
June 30, 2024

Asset Class[1]	Assumed Asset Allocation	Real Return[1],[2]
Global Equity - Cap-weighted	30.00%	4.54%
Global Equity - Non-Cap-weighted	12.00%	3.84%
Private Equity	13.00%	7.28%
Treasury	5.00%	0.27%
Mortgage-backed Securities	5.00%	0.50%
Investment Grade Corporates	10.00%	1.56%
High Yield	5.00%	2.27%
Emerging Market Debt	5.00%	2.48%
Private Debt	5.00%	3.57%
Real Assets	15.00%	3.21%
Leverage	-5.00%	-0.59%

(1) An expected inflation of 2.30% used for this period.

(2) Figures are based on the 2021 Asset Liability Management study.

Measurement Date
June 30, 2023

Asset Class[1]	Assumed Asset Allocation	Real Return[1],[2]
Global Equity - Cap-weighted	30.00%	4.54%
Global Equity - Non-Cap-weighted	12.00%	3.84%
Private Equity	13.00%	7.28%
Treasury	5.00%	0.27%
Mortgage-backed Securities	5.00%	0.50%
Investment Grade Corporates	10.00%	1.56%
High Yield	5.00%	2.27%
Emerging Market Debt	5.00%	2.48%
Private Debt	5.00%	3.57%
Real Assets	15.00%	3.21%
Leverage	-5.00%	-0.59%

(1) An expected inflation of 2.30% used for this period.

(2) Figures are based on the 2021 Asset Liability Management study.

6. EMPLOYEE RETIREMENT PLAN (CONTINUED)

DISCOUNT RATE

The discount rate used to measure the total pension liability was 6.90% for measurement dates as of 2024 and 2023. The projection of cash flows used to determine the discount rate assumed that contributions from plan members will be made at the current member contribution rates and that contributions from employers will be made at statutorily required rates, actuarially determined. Based on those assumptions, the Plan's fiduciary net position was projected to be available to make all projected future benefit payments of current plan members. Therefore, the long-term expected rate of return on plan investments was applied to all periods of projected benefit payments to determine the total pension liability.

Changes of Benefit Terms - In 2022, SB 1168 increased the standard retiree lump sum death benefit from $500 to $2,000 for any death occurring on or after July 1, 2023. The impact, if any, is included in the changes of benefit terms.

CHANGES IN ASSUMPTIONS

In determining the long-term expected rate of return, CalPERS took into account long-term market return expectations as well as the expected pension fund cash flows. Projected returns for all asset classes were estimated, combined with risk estimates, and used to project compound (geometric) returns over the long term. The discount rate used to discount liabilities was informed by the long-term projected portfolio return. In addition, demographic assumptions and the inflation rate assumption were changed in accordance with the 2021 CalPERS Experience Study and Review of Actuarial Assumptions.

There were no assumption changes in valuation dated June 30, 2023 (2024 measurement date).

CHANGES IN THE NET PENSION LIABILITY (ASSET)

The changes in the Electric Utility's proportionate share of the net pension liability/(asset) as of June 30, 2025 (measurement date 2024) and 2024 (measurement date June 30, 2023) for the Plan are as follows:

June 30, 2025	Net Pension Liability/ (Asset)	Proportion of the Plan
Proportion - Reporting date June 30, 2025 (Measurement Date June 30, 2024)	$ 52,907	28.27 %
Proportion - Reporting date June 30, 2024 (Measurement Date June 30, 2023)	44,227	28.53 %
Changes - Increase / (Decrease)	8,680	-0.26 %
June 30, 2024		
Proportion - Reporting date June 30, 2024 (Measurement Date June 30, 2023)	44,227	28.53 %
Proportion - Reporting date June 30, 2023 (Measurement Date June 30, 2022)	38,748	29.42 %
Changes - Increase / (Decrease)	5,479	-0.89 %

6. EMPLOYEE RETIREMENT PLAN (CONTINUED)

PENSION EXPENSES AND DEFERRED OUTFLOWS/INFLOWS OF RESOURCES RELATED TO PENSION

For the fiscal years ended June 30, 2025 and 2024, the Electric Utility recognized pension expense of $17,352 and $13,766, respectively. At June 30, 2025 and 2024, the Electric Utility reported deferred outflows/(inflows) of resources related to pension from the following sources:

	June 30, 2025		June 30, 2024	
	Deferred Outflows of Resources	Deferred Inflows of Resources	Deferred Outflows of Resources	Deferred Inflows of Resources
Pension contribution subsequent to the measurement date	$ 7,765	$ -	$ 6,060	$ -
Changes in Assumptions	348	-	2,106	-
Difference between expected and actual experience	12,942	(312)	2,505	(1,892)
Net difference between projected and actual earnings on pension plan investments	7,479	-	20,347	-
Total	$ 28,534	$ (312)	$ 31,018	$ (1,892)

Deferred outflows of resources related to contributions subsequent to the measurement date reported in prior year was recognized as a reduction of the net pension liability in the year ended June 30, 2025 and 2024, respectively.

At June 30, 2025 and 2024, the Electric Utility reported deferred outflows/(inflows) of resources related to pension to be recognized as pension expense as follows:

Year Ended June 30	Deferred Outflows/ (Inflows) of Resources
2026	$ 5,966
2027	16,850
2028	(125)
2029	(2,234)
Total	$ 20,457

Year Ended June 30	Deferred Outflows/ (Inflows) of Resources
2025	$ 5,101
2026	3,189
2027	14,174
2028	602
Total	$ 23,066

6. EMPLOYEE RETIREMENT PLAN (CONTINUED)

PENSION EXPENSES AND DEFERRED OUTFLOWS/INFLOWS OF RESOURCES RELATED TO PENSION (CONTINUED)

On July 12, 2021, CalPERS reported a preliminary 21.3% net return on investments for fiscal year 2020-21. Based on the thresholds specified in CalPERS Funding Risk Mitigation policy, the excess return of 14.3% prescribed a reduction in investment volatility that corresponds to a reduction in the discount rate used for funding purposes of 0.20%, from 7.00% to 6.80%. Since CalPERS was in the final stages of the four-year Asset Liability Management (ALM) cycle, the board elected to defer any changes to the asset allocation until the ALM process concluded, and the board could make its final decision on the asset allocation in November 2021.

On November 17, 2021, the board adopted a new strategic asset allocation. The new asset allocation along with the new capital market assumptions, economic assumptions and administrative expense assumption supported a discount rate of 6.90% (net of investment expense but without a reduction for administrative expense) for financial reporting purposes. This included a reduction in the price inflation assumption from 2.50% to 2.30% as recommended in the November 2021 CalPERS Experience Study and Review of Actuarial Assumptions. This study also recommended modifications to retirement rates, termination rates, mortality rates and rates of salary increases that were adopted by the board. These new assumptions were reflected in the GASB 68 accounting valuation reports for the June 30, 2022, measurement date.

Events Subsequent to June 30, 2023 valuation date (2024 measurement date) - There were no subsequent events that would materially affect the results in this disclosure.

SENSITIVITY OF THE NET PENSION LIABILITY (ASSET) TO CHANGES IN THE DISCOUNT RATE

The following presents the Electric Utility’s proportionate share of the net pension liability of the Plan, calculated using the discount rate of 6.90% (measurement date June 30, 2024 and 2023), as well as what the Electric Utility’s proportionate share of the net pension liability would be if it was calculated using a discount rate that is 1-percentage point lower or 1-percentage point higher than the current rate:

	Measurement Date June 30, 2024			Measurement Date June 30, 2023		
	Discount Rate -1% (5.90%)	Current Discount Rate (6.90%)	Discount Rate +1% (7.90%)	Discount Rate -1% (5.90%)	Current Discount Rate (6.90%)	Discount Rate +1% (7.90%)
Electric Utilitiy's proportionate share of the Plan's net pension liability	$ 120,564	$ 52,907	$ (2,751)	$ 108,540	$ 44,227	$ (8,639)

Detailed information about the Plan’s fiduciary net position is available in the separately issued CalPERS financial reports.

7. OTHER POST-EMPLOYMENT BENEFITS (OPEB)

PLAN DESCRIPTION

Employees of the Electric Utility participate in the City's defined benefit OPEB plan, Retiree Health Plan, provides continuation of medical (including prescription drugs) and dental coverage benefits to retirees and surviving spouses in the form of an implied rate subsidy. The Retiree Health Benefits plan is a single employer defined benefit OPEB plan administered by the City. No assets are accumulated in a trust that meets the criteria in paragraph 4 of GASB Statement No. 75.

BENEFITS PROVIDED

Eligibility for continuation of coverage requires retirement from the City and CalPERS with at least 5 years of City service. The retiree is responsible for 100% of the premium cost for coverage, which is based on the blended experience of both the active and retired employees. The City is not required by law or contractual agreement to provide funding other than the pay-as-you-go amount necessary to provide current benefits to eligible retirees and beneficiaries. Retiree and spousal coverage terminate when the retiree becomes covered under another employer health plan, or when the retiree reaches Medicare eligibility age, which is currently age 65. However, retiree benefits continue to the surviving spouse if the retiree elects the CalPERS survivor annuity.

ACTUARIAL ASSUMPTIONS

The total OPEB liability was determined by actuarial valuation as of 2024 and 2023 using the following actuarial assumptions:

	Miscellaneous - Current Year	Miscellaneous - Prior Year
Valuation Date	June 30, 2023	June 30, 2023
Measurement Date	June 30, 2024	June 30, 2023
Actuarial Cost Method	Pay-as-you-go for implicit rate subsidy	Pay-as-you-go for implicit rate subsidy
Actuarial Assumptions		
Discount Rate	Bond Buyer 20 Index at June 30, 2023 resulting in a rate of 3.93%	Bond Buyer 20 Index at June 30, 2023 resulting in a rate of 3.65%
Inflation Rate	2.50% per annum	2.50% per annum
Payroll Increases	2.75% per year. Since benefits do not depend on salary (as they do for pensions), this assumption is only used to determine the accrual pattern of the Actuarial Present Value of Projected Benefit Payments.	2.75% per year. Since benefits do not depend on salary (as they do for pensions), this assumption is only used to determine the accrual pattern of the Actuarial Present Value of Projected Benefit Payments.
Mortality	2021 CalPERS Retiree Mortality Table for the appropriated population	2021 CalPERS Retiree Mortality Table for the appropriated population
Healthcare Trend Rates	Medical trend in future years has been updated to 4.00% for all years.	Medical trend in future years has been updated to 4.00% for all years.

CHANGES OF ASSUMPTIONS

In 2024, the discount rate was changed from 3.65% to 3.93%. In 2023, the discount rate was changed from 3.54% to 3.65%.

7. OTHER POST-EMPLOYMENT BENEFITS (OPEB) (CONTINUED)

SENSITIVITY OF TOTAL OPEB LIABILITY TO CHANGES IN HEALTHCARE COST TREND RATES

The following presents the Electric Utility's proportionate share of the City's total OPEB liability, calculated using the healthcare trend rate of 4.00% for the measurement date as of 2024 and 2023, as well as what the Electric Utility's total OPEB liability would be if it was calculated using a healthcare cost trend rate that is 1-percentage-point lower or 1-percentage-point higher than the current rate:

	Measurement Date June 30, 2024			Measurement Date June 30, 2023		
	1% Decrease	Current healthcare cost trend rate 4%	1% Increase	1% Decrease	Current healthcare cost trend rate 4%	1% Increase
Electric Utility's proportionate share of the total OPEB liability	$ 8,011	$ 10,807	$ 10,051	$ 8,014	$ 10,446	$ 10,396

SENSITIVITY OF TOTAL OPEB LIABILITY TO CHANGES IN DISCOUNT RATES

The following presents the Electric Utility's proportionate share of the City's total OPEB liability, calculated using the discount rate of 3.93% and 3.65% for measurement dates of 2024 and 2023 respectively, as well as what the Electric Utility's total OPEB liability would be if it was calculated using a discount rate that is 1-percentage-point lower or 1-percentage-point higher than the current rate:

	Measurement Date June 30, 2024			Measurement Date June 30, 2023		
	1% Decrease (2.93%)	Current Discount Rate (3.93%)	1% Increase (4.93%)	1% Decrease (2.65%)	Current Discount Rate (3.65%)	1% Increase (4.65%)
Electric Utility's proportionate share of the total OPEB liability	$ 9,612	$ 10,807	$ 8,060	$ 9,942	$ 10,446	$ 8,337

CHANGE IN TOTAL OPEB LIABILITY

For fiscal years ended June 30, 2025 and 2024, the Electric Utility recognized total OPEB expense of $526 and $474 respectively. The following table shows the change in the Electric Utility's proportionate share of the City's total OPEB liability for the year ended June 30, 2025 (measurement date June 30, 2024) and the year ended June 30, 2024 (measurement date June 30, 2023):

June 30, 2025	Net OPEB Liability	Proportion of the Plan
Proportion - Reporting date June 30, 2025 (Measurement Date June 30, 2024)	$ 10,807	18.06 %
Proportion - Reporting date June 30, 2024 (Measurement Date June 30, 2023)	10,446	18.68 %
Changes - Increase / (Decrease)	361	-0.62 %
June 30, 2024		
Proportion - Reporting date June 30, 2024 (Measurement Date June 30, 2023)	10,446	18.68 %
Proportion - Reporting date June 30, 2023 (Measurement Date June 30, 2022)	9,837	21.63 %
Changes - Increase / (Decrease)	609	-2.95 %

7. OTHER POST-EMPLOYMENT BENEFITS (OPEB) (CONTINUED)

DEFERRED OUTFLOWS/INFLOWS OF RESOURCES RELATED TO OPEB

At June 30, 2025 and 2024, the Electric Utility reported deferred outflows/(inflows) of resources related to OPEB from the following sources:

	Deferred Outflows of Resources	Deferred Inflows of Resources
Difference between expected and actual experience	$ 195	$ (479)
Changes of assumptions	754	(1,511)
Contributions subsequent to measurement date	335	-
Total	$ 1,284	$ (1,990)

	Deferred Outflows of Resources	Deferred Inflows of Resources
Difference between expected and actual experience	$ 218	$ (564)
Changes of assumptions	991	(1,474)
Contributions subsequent to measurement date	289	-
Total	$ 1,498	$ (2,038)

At June 30, 2025 and 2024, the Electric Utility reported deferred outflows/(inflows) of resources related to OPEB to be recognized as OPEB expense as follows:

Year Ended June 30	Deferred Outflows/ (Inflows) of Resources
2026	$ 8
2027	16
2028	16
2029	(217)
2030	(215)
Thereafter	(649)
Total	$ (1,041)

Year Ended June 30	Measurement Date
2025	$ (13)
2026	32
2027	40
2028	40
2029	(194)
Thereafter	(734)
Total	$ (829)

8. RESTRICTED NET POSITION

The California Code of Regulations establishes a restriction on the use of proceeds obtained from the sale of greenhouse gas allowances at auctions held pursuant to California's Cap-and-Trade Program. The proceeds are to be used exclusively for the benefit of retail ratepayers of each electrical distribution utility and may not be used for the benefit of entities or persons other than such ratepayers. In addition, the Low Carbon Fuel Standard Program (LCFS) was established and restricts the use of the proceeds obtained from the sale of LCFS credits. The available funds are to be utilized for qualifying projects that support the Electric Utility's customers who are existing and future electric vehicle owners. Accordingly, a reserve for regulatory requirements has been established by restricting assets and reserving a portion of net position. See Note 11 for additional information regarding the Cap-and-Trade Program and the LCFS Program.

Pursuant to applicable bond indentures, a reserve for debt service has been established by restricting assets and reserving a portion of net position. Bond indentures for the Electric Utility's electric revenue and refunding bonds require debt service reserves that equate to the maximum annual debt service required in future years and bond service reserves of three months interest and nine months principal due in the next fiscal year. Variable rate revenue and refunding bonds require 110% of the monthly accrued interest to be included in the reserve. During fiscal year 2023-2024, the Electric revenue bonds requiring reserves (2008A & C) were fully refunded with 2024A issue. Certain issues have no debt service reserve requirements (2010A, 2019A, 2023A, and 2024A). During fiscal year 2024-2025, the Electric revenue bonds that have no debt service reserve requirements (2011A and 2013A) were fully refunded with 2024A and 2023A issues, respectively. See Note 4 for further discussion related to the Electric Utility's debt issuances.

Pursuant to the Twenty-First Supplemental Resolution, as stated in the Electric Revenue Bonds, Issue of 2024A indentures, the Fiscal Agent will establish, maintain and hold in trust a separate account designated as the "Electric Revenue Bonds Issue of 2024 Rebate Account." All money at any time deposited in the Electric Revenue Bonds Issue of 2024 Rebate Account will be held by the Fiscal Agent in the restricted account for payment to the United States Treasury. Within 55 days of the end of each bond year, the Electric Utility will calculate the amount of rebatable arbitrage. The Fiscal Agent will pay to the United States Treasury, not later than 60 days after the end of the 5th bond year; and each applicable 5th bond year thereafter, an amount equal to at least 90% of the Rebatable Arbitrage calculated as of the end of such bond year; not later than 60 days after the payment of all of the 2024A Bonds, an amount equal to 100% of the Rebatable Arbitrage calculated as of the end of such applicable bond year, and any income attributable to the Rebatable Arbitrage (Section 148(f) of the Code and Section 1.148 3 of the Treasury Regulations). During the interim computation period from 2/1/2024 through 2/1/2025, the excess Arbitrage Rebate Liability in the amount of $2,527 was computed. As of June 30, 2025, the Electric Utility recorded an arbitrage liability related to the 2024 Electric Revenue Bonds Series A. See Note 4 for further discussion related to the Electric Utility's debt issuances.

In the Annual Valuation Report as of June 30, 2021, CalPERS reported an investment return of 21.3%. These positive returns contributed to the reduction of the unfunded accrued liability (UAL). The City did not eliminate the budgeted UAL payments during the amendment of the fiscal year 2023-24 budget, but rather redirected those budgeted payments the respective funds' restricted cash and investments held at fiscal agent and restricted fund balance for future UAL costs. See Note 6 for further discussion related to the UAL.

9. JOINTLY-GOVERNED ORGANIZATIONS

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

On November 1, 1980, the City joined with the Imperial Irrigation District and the cities of Los Angeles, Anaheim, Vernon, Azusa, Banning, Colton, Burbank, Glendale and Pasadena to create the Southern California Public Power Authority (SCPPA) by a Joint Powers Agreement under the laws of the State of California. As of July 2001, the City of Cerritos was admitted as an additional member of SCPPA. The primary purpose of SCPPA is to plan, finance, develop, acquire, construct, operate and maintain projects for the generation and transmission of electric energy for sale to its participants. SCPPA is governed by a Board of Directors, which consists of one representative from each of the members. During fiscal years ended June 30, 2025 and 2024, the Electric Utility paid approximately $26,212 and $24,739, respectively, to SCPPA under various take-or-pay and renewable contracts that are described in greater detail in Note 11. These payments are reflected as a component of production and purchased power and transmission expenses in the financial statements.

POWER AGENCY OF CALIFORNIA

On July 1, 1990, the City joined with the cities of Azusa, Banning and Colton to create the Power Agency of California (PAC) by a Joint Powers Agreement under the laws of the State of California. The City of Anaheim joined PAC on July 1, 1996. The primary purpose of PAC is to take advantage of synergies and economies of scale as a result of the five cities acting in concert. PAC has the ability to plan, finance, develop, acquire, construct, operate and maintain projects for the generation and transmission of electric energy for sale to its participants. PAC is governed by a Board of Directors, which consists of one representative from each of the members. The term of the Joint Powers Agreement is 50 years. Effective June 30, 2001, PAC was placed in an inactive status by the Board of Directors. The Agency can only be reactivated by authorization of the Agency Board.

10. JOINTLY-OWNED UTILITY PROJECT - SONGS

The City has a 1.79 percent undivided ownership interest in Units 2 and 3 of SONGS, located south of the City of San Clemente in northern San Diego County. Both Units 2 and 3 of SONGS were permanently retired in June 2013. Consequently, the units are no longer a source of supply for the Electric Utility, but remain associated with certain of its costs, including those associated with the units' shutdown and decommissioning.

The other owners are SCE, with a 78.21 percent interest (including the 3.16 percent interest it acquired from the City of Anaheim in 2006), and San Diego Gas & Electric Company (SDG&E), with a 20.00 percent interest.

In 2005, the California Public Utilities Commission (CPUC) authorized a project to install four new steam generators in Units 2 and 3 at SONGS and remove and dispose of the predecessor generators. SCE completed the installation of these steam generators in 2010 and 2011 for Units 2 and 3, respectively. The Electric Utility's share of the cost to replace the steam generators was approximately $13.4 million. Replacement of the steam generators was expected to enable plant operations to continue through at least 2022, and perhaps beyond, subject to the approval of the NRC.

In January 2012, a water leak occurred in one of the heat transfer tubes of Unit 3's steam generators, causing it to be shut down. At that time, Unit 2 was off-line for a planned outage when unexpected wear in areas of tube-to-support structure were found. Units 2 and 3 remained off-line for extensive inspections, testing and analysis of their steam generators. On June 7, 2013, SCE unilaterally announced its plan to retire Units 2 and 3 permanently.

Nuclear Decommissioning. As a result of SCE's decision to permanently retire SONGS Units 2 and 3, the decommissioning phase of the plant began in June 2013. The process of decommissioning the nuclear power plant is expected to take many years and is governed by NRC regulations. According to SCE's decommissioning cost estimate document as of March 2018 in 2017 dollars, total decommissioning costs for Units 2 and 3 were estimated at $4.7 billion, of which the Electric Utility's share was $84 million.

In August 2021, SCE provided the updated decommissioning cost estimate report in 2020 dollars. According to the update, total decommissioning costs for Units 2 and 3 are estimated at $5.2 billion, of which the Electric Utility's share is $93.8 million.

In August 2024, SCE provided the updated decommissioning cost estimate report in 2023 dollars. According to the update, total decommissioning costs for Units 2 and 3 are estimated at $5.7 billion, of which the Electric Utility's share is $102.6 million.

Nuclear Decommissioning Funding and Liability. As of June 30, 2025, the Electric Utility has set aside $41,536 in cash investments with the trustee and $12,227 in a designated decommissioning reserve for the Electric Utility's estimated share of the decommissioning costs. Increases to the funds held for decommissioning liability are from investment earnings. The investment earnings are included in investment income in the Electric Utility's financial statements. An equivalent amount is reflected as decommissioning expense, which is considered part of production and purchased power. Decreases to the funds held for decommissioning liability are from actual funds drawn from the trust for decommissioning costs invoiced by SCE.

On February 23, 2016, the City Council adopted a resolution authorizing the commencement of SONGS decommissioning effective June 7, 2013. This resolution allows the Electric Utility to access the decommissioning trust funds to pay for its share of decommissioning costs. The Electric Utility began drawing decommissioning trust funds to pay for decommissioning costs in the fiscal year ended June 30, 2017. As of June 30, 2025, the Electric Utility has paid to date $55,593 in decommissioning obligations, which have been reimbursed by the trust funds.

As of June 30, 2025 and 2024, decommissioning liability balance was $46,965 and $46,082, respectively, with a portion reflected as current liabilities payable from restricted assets. As a result of the updated SCE decommissioning cost estimate and the increase in the Electric Utility's estimated share, the decommissioning liability was increased by $5.8 million in fiscal year 2025. The offset of this liability increase was recorded as a decommissioning liability expense in fiscal year 2024/25.

The Electric Utility no longer provides additional funding to the trustee. However, since the decommissioning cost estimate is subject to a number of uncertainties including the cost of disposal of nuclear waste, site remediation costs, as well as a number of other assumptions and estimates, the Electric Utility has set aside funds in the designated decommissioning reserve of $2,000 per year through fiscal year 2024, as approved by the Board of Public Utilities and City Council. Beginning in fiscal year 2025, the Electric Utility will continue to set aside funds in the designated decommissioning reserve of $1,000 per year, as approved by the Board of Public Utilities and City Council.

10. JOINTLY-OWNED UTILITY PROJECT - SONGS (CONTINUED)

	Balance As of 6/30/2023	Additions	Reductions	Balance As of 6/30/2024	Additions	Reductions	Balance As of 6/30/2025	Due Within One Year
Nuclear decommissioning liability	$ 48,873	$ 863	$ (3,654)	$ 46,082	$ 6,938	$ (6,055)	$ 46,965	$ 6,887

11. COMMITMENTS

The Electric Utility has a power purchase contract with Intermountain Power Agency (IPA) for the delivery of electric power. The Electric Utility's share of IPA power is equal to 7.6 percent, or approximately 137.1 MW, of the net generation output of IPA's 1,800 MW central Utah coal-fueled generating station, known as Intermountain Power Project (IPP). The contract expires in 2027.

The contract constitutes an obligation of the Electric Utility to make payments solely from operating revenues. The power purchase contract requires the Electric Utility to pay certain minimum charges that are based on debt service requirements and other fixed costs. Such payments are considered a cost of production.

On September 29, 2006, Senate Bill (SB) 1368 was enacted into law. The bill requires electric service providers to limit financial investments in power plants to those that adhere to greenhouse gas performance standards as determined by the Public Utilities Commission. Pursuant to this legislation, the Electric Utility is prohibited from renewing its participation in IPP if it remains a coal fueled generating resource.

In order to facilitate the continued participation in the IPP, the IPA Board issued the Second Amendatory Power Sales Contract, which amended the IPP Contract allowing the plant to replace the coal units with combined cycle natural gas units by July 1, 2025. On June 16, 2015, the City Council approved the IPP renewal agreements, including the Second Amendatory Power Sales Contract and the Renewal Power Sales Contract, and authorized participation in the IPP Repower Project for up to 5 percent in generation capacity or 60 MW. The Second Amendatory Power Sales Contract became effective March 16, 2016.

On January 5, 2017, the Electric Utility executed the Renewal Power Sales Contract and the Electric Utility accepted an offer of 4.167 percent entitlement or 50 MW generation capacity in the IPP Repower Project based on the 1,200 MW designed capacity, which is within the maximum participation level approved by the City Council. The Electric Utility's corresponding Southern Transmission System allocation is 5.278 percent or approximately 127 MW. Further, under the Renewal Power Sales Contract, the Electric Utility had the right to exit from the Repower Project by no later than November 1, 2019, if it is determined that the Repower Project is not cost beneficial to its customers.

On September 11, 2018, the City Council approved "Alternative Repowering" of the IPP Repower Project, which reduced the design capacity of the future plant from 1,200 MW to 840 MW.

On May 7, 2019, the City Council authorized termination of the Renewal Power Sales Contract between the IPA and the Electric Utility effective November 1, 2019, and the Electric Utility's exit from the IPP Repower Project upon the expiration date of the current Power Sales Contract on June 15, 2027, due to numerous uncertainties surrounding the IPP Repower Project.

The Electric Utility is a member of SCPPA, a joint powers agency (see Note 9 for further discussion). SCPPA provides for the financing and construction of electric generating and transmission projects for participation by some or all of its members. To the extent the Electric Utility participates in take-or-pay projects developed by SCPPA, it has entered into Power Purchase or Transmission Service Agreements, entitling the Electric Utility to the power output or transmission service, as applicable, and the Electric Utility will be obligated for its proportionate share of the project costs whether or not such generation output of transmission service is available.

The projects and the Electric Utility's proportionate share of SCPPA's obligations, including final maturities and contract expirations are as follows:

Project	Percent Share	Entitlement	Final Maturity	Contract Expiration
Palo Verde Nuclear Generating Station	5.40 %	12.3 MW	2017	2030
Southern Transmission System	10.20 %	244.0 MW	2027	2027
Mead-Phoenix Transmission	4.00 %	18.0 MW	2020	2030
Mead-Adelanto Transmission	13.50 %	118.0 MW	2020	2030

11. COMMITMENTS (CONTINUED)

As part of the take-or-pay commitments with IPA and SCPPA, the Electric Utility has agreed to pay its share of current and long-term obligations. Management intends to pay these obligations from operating revenues received during the year that payment is due. A long-term obligation has not been recorded on the accompanying financial statements for these commitments. Take-or-pay commitments terminate upon the later of contract expiration or final maturity of outstanding bonds for each project.

The outstanding debts associated with the take-or-pay obligations have fixed interest rates, which range from 4.00 percent to 5.00 percent. The schedule below details the amount of principal and interest that is due and payable by the Electric Utility as part of the take-or-pay contract for each project in the fiscal year indicated:

	IPA[1]	SCPPA[2]	Total
Debt Service Payment (in thousands) Year Ending June 30,	Intermountain Power Project	Southern Transmission System	All Projects
2026	$ 6,897	$ 11,034	$ 17,931
2027	10,975	12,859	23,834
2028	-	8,647	8,647
Total	$ 17,872	$ 32,540	$ 50,412

[1] The Electric Utility's contract with IPA expires in 2027. The Electric Utility will not be responsible for the proportionate share of the IPA Revenue bonds after the contract expires.

[2] During fiscal year 2023-24, STS issued 3 Renewal Project bonds. During fiscal year 2024-25, STS issued 2 Renewal Project bonds. The Electric Utility's contract with STS through SCPPA expires on June 15, 2027. The Electric Utility will be responsible for the proportionate share of the STS bonds up to the July 1, 2027 debt payment date.

In addition to debt service, the Electric Utility's entitlements require the payment of fuel costs, operating and maintenance, administrative and general and other miscellaneous costs associated with the generation and transmission facilities discussed above. These costs do not have a similar structured payment schedule as debt service varies each year. The costs incurred for the years ended June 30, 2025 and 2024, are as follows (in thousands):

Fiscal Year	Intermountain Power Project[1]	Palo Verde Nuclear Generating Station[1]	Southern Transmission System	Mead-Phoenix Transmission	Mead-Adelanto Transmission	All Projects
2025	$ 31,660	$ 3,414	$ 5,124	$ 58	$ 640	$ 40,896
2024	$ 20,106	$ 3,135	$ 3,771	$ 76	$ 640	$ 27,728

[1] Excludes variable cost.

These costs are included in production and purchased power or transmission expense on the Statements of Revenues, Expenses and Changes in Net Position.

The Electric Utility has become a Participating Transmission Owner with the California Independent System Operator (CAISO) and has turned over the operational control of its transmission entitlements including the Southern Transmission System, Mead-Phoenix, and Mead-Adelanto Transmission Projects. In return, users of California's high voltage transmission grid are charged for, and the Electric Utility receives reimbursement for, transmission revenue requirements, including the costs associated with these three transmission projects.

HOOVER UPRATING PROJECT

The Electric Utility's initial entitlement in the Hoover project through SCPPA terminated on September 30, 2017. On August 23, 2016, the City Council approved a 50-year Electric Service Contract (ESC) and an Amended and Restated Implementation Agreement (IA) with the Western Area Power Administration (Western) Bureau of Reclamation for 30 MW of hydroelectric power. The contract with Western is effective as of October 1, 2017. The ESC extended the Electric Utility's 30 MW entitlement in the Hoover project through 2067. The IA is a supplemental agreement to the ESC that establishes administrative, budgetary and project oversight by creating project committees and a process for decision making in plant operations.

11. COMMITMENTS (CONTINUED)

NUCLEAR INSURANCE

The Price-Anderson Act (the Act) requires that all utilities with nuclear generating facilities purchase the maximum private primary nuclear liability insurance available ($500 million) and participate in the industry's secondary financial protection plan. The secondary financial protection program is the industry's retrospective assessment plan that uses deferred premium charges from every licensed reactor owner if claims and/or costs resulting from a nuclear incident at any licensed reactor in the United States were to exceed the primary nuclear insurance at that plant's site. Effective January 1, 2024, the Act limits liability from third-party claims to approximately $16.3 billion per incident. Under the industry-wide retrospective assessment program provided for under the Act, assessments are limited to $165.9 million per reactor for each nuclear incident occurring at any nuclear reactor in the United States, with payments under the program limited to $24.7 million per reactor, per year, per event to be indexed for inflation every five years. Based on the Electric Utility's interest in Palo Verde, the Electric Utility would be responsible for a maximum assessment of $1.6 million, limited to payments of $0.2 million per incident, per year. If the public liability limit above is insufficient, federal regulations may impose further revenue-raising measures to pay claims, including a possible additional assessment on all licensed reactor operators.

RENEWABLE PORTFOLIO STANDARD (RPS)

On April 12, 2011, the California Renewable Energy Resources Act (SBX1-2) was signed into law by the Governor, which officially created the first set of tiered RPS targets of 20% by 2013, 25% by 2016 and 33% by 2020. SBX1-2 specified that publicly owned utilities must meet these defined targets via interim Compliance Period (CP) targets to achieve the end goal of 33% RPS by December 31, 2020 as follows: CP1 - an average of 20 percent of retail sales during the 3-year period from 2011-2013; CP2 – no less than 25 percent of retail sales by December 31, 2016; and CP3 – no less than 33 percent of retail sales by December 31, 2020. The Riverside Public Utilities Board and City Council approved the RPS Enforcement Program required by SBX1-2 on November 18, 2011 and December 13, 2011, respectively, and further approved the Electric Utility's RPS Procurement Plan (a.k.a. Procurement Policy) implementing the new RPS mandates on May 3, 2013 and May 14, 2013, respectively. The Electric Utility met the procurement requirements of SBX1-2 for CP1 (2011-2013), CP2 (2014-2016), and CP3 (2017-2020). The additional future mandates are expected to be met with resource procurement actions as outlined in the Electric Utility's RPS Procurement Plan. For calendar year 2024, renewable resources provided 39 percent of retail sales requirements.

On October 7, 2015, the Governor signed into law SB 350 increasing the RPS mandate from 33 percent by 2020 to 50 percent by December 31, 2030. In addition, SB 350 required that an updated RPS Procurement Policy be approved and adopted before January 1, 2019 and be incorporated into the Electric Utility's Integrated Resource Plan. An updated 2018 Renewable Energy Procurement Policy was adopted by the Board and City Council on September 10, 2018 and October 9, 2018, respectively. The Electric Utility expects to be able to substantially meet the increased RPS mandates imposed by SB 350 with the actions described in the updated procurement policy and the portfolio of renewable resources outlined below.

On September 10, 2018, the 100 Percent Clean Energy Act of 2018 (SB 100) was signed into law by the California Governor. This bill further increases the RPS goals of SBX1-2 and SB 350 while maintaining the 33 percent RPS target by December 31, 2020, but modifying the RPS percentages to be 44 percent by December 31, 2024, 52 percent by December 31, 2027, 60 percent by December 31, 2030, with an end goal of 100 percent of total retail sales of electricity in California generated from eligible renewable energy resources and zero-carbon resources by December 31, 2045. It is expected that the California Energy Commission will have further guidance and enforcement procedures for publicly owned utilities to meet these increased mandates. The Electric Utility will continue to monitor the outcome and impacts of any upcoming workshops and regulations in meeting the new requirements.

In an effort to increase the share of renewables in the Electric Utility's power portfolio, the Electric Utility entered into power purchase agreements (PPA) and power sales agreements (PSA) with various entities described below in general on a "take-and-pay" basis. The contracts in the following tables were executed as part of compliance with RPS mandates.

11. COMMITMENTS (CONTINUED)

RENEWABLE PORTFOLIO STANDARD (RPS) (CONTINUED)

Long-term renewable PPAs and PSAs in operation (dollars in thousands):

Supplier	Type	Maximum Contract[1]		Contract Expiration	Estimated Annual Cost for 2025
WKN Wagner	Wind	6.0	MW	12/22/2032	$ 1,485
Terraform Power - AP North Lake	Photovoltaic	20.0	MW	08/11/2040	5,130
Onward Energy - Columbia II	Photovoltaic	11.1	MW	12/22/2034	2,314
Salka Cabazon Wind, LLC	Wind	39.0	MW	12/31/2027	4,299
Arevon - Kingbird Solar B, LLC	Photovoltaic	14.0	MW	12/31/2036	2,867
AES - Summer Solar	Photovoltaic	10.0	MW	12/31/2041	1,748
AES - Antelope Big Sky Ranch	Photovoltaic	10.0	MW	12/31/2041	1,748
AES - Antelope DSR 1 Solar	Photovoltaic	25.0	MW	12/19/2036	3,826
Arevon - Tequesquite Landfill Solar	Photovoltaic	7.3	MW	12/31/2040	1,488
Roseburg Forest Products[2]	Biomass	N/A		02/16/2026	119
CalEnergy - Salton Sea Portfolio	Geothermal	86.0	MW	12/31/2039	58,157
Atlantica - Coso Geothermal	Geothermal	10.0	MW	12/31/2041	6,050
Total		238.4	MW		$ 89,231

[1]All contracts are contingent on energy delivered from specific related generating facilities. The Electric Utility has no commitment to pay any amounts except for energy delivered on a monthly basis from these facilities except for any economic curtailments directed by the Electric Utility.

[2]This supply is only available to satisfy SB 859 requirements.

Long-term renewable PPAs with expected delivery:

Supplier	Type	Maximum Contract[1]	Expected Delivery	Energy Delivery No Later Than	Contract Term In Years
SunZia Wind Power Co.	Wind	125.0 MW	03/31/2026	03/31/2027	15
Atlantica - Coso Geothermal	Geothermal	20.0 MW	01/01/2027	01/01/2027	15
Total		145.0 MW			

[1]All contracts are contingent on energy delivered from specific related generating facilities. The Electric Utility has no commitment to pay any amounts except for energy delivered on a monthly basis from these facilities except for any economic curtailments directed by the Electric Utility.

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

On May 14, 2013, the City Council approved a new 25-year PPA with CalEnergy, the parent of Salton Sea, for additional renewable geothermal power. The PPA provides power from a portfolio of ten geothermal generating units, instead of a single generating unit, with an increasing amount of delivery that started with 20 MW in 2016, increasing to 40 MW in 2019, and 86 MW in 2020. The initial price under the agreement was $72.85 per megawatt-hour (MWh) in calendar year 2016, which will escalate at 1.5 percent annually for the remaining term of the agreement. Similar to other renewable PPAs, the Electric Utility is only obligated for purchases of energy delivered to the City.

Concurrently, the pricing under the Salton Sea PPA was amended to conform to pricing in the new PPA with CalEnergy through the remaining term of the Salton Sea PPA. The pricing under the Salton Sea PPA increased by approximately $7.57 per MWh, commencing July 1, 2013 to $69.66 per MWh, with an escalation of 1.5 percent annually thereafter, reflecting the exchange of benefits for a substantially lower pricing under the new PPA. The cost increase under the Salton Sea PPA and accrual of the prepayment ended as of May 31, 2020. As of June 30, 2025 and 2024, the Electric Utility's prepayment of future contractual obligations was $11,174 and $11,689, respectively. This prepayment is recorded on the Statements of Net Position as unamortized purchased power, to be amortized over the term of the CalEnergy PPA. The CalEnergy PPA commenced in February 2016. As of June 30, 2025 and 2024, the Electric Utility has recorded $515 and $641, respectively, in amortization related to the unamortized purchased power.

On October 16, 2012, the Electric Utility entered into a 25-year PPA with AP North Lake, LLC (AP North) for 20 MW of solar photovoltaic energy generated by a new facility located in the City of Hemet, California. The AP North Lake Project

11. COMMITMENTS (CONTINUED)

RENEWABLE PORTFOLIO STANDARD (RPS) (CONTINUED)

became fully operational in August 2015. The project is expected to generate 55,000 MWh of renewable energy per year at a levelized cost of $95 per MWh for the term of the PPA. After a series of ownership changes, AP North Lake is now owned by Terraform Power.

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

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

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

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

On December 6, 2013, the Electric Utility and FPL Energy Cabazon Wind, LLC (Cabazon Wind) entered into a 10-year PPA for 39 MW of renewable wind energy from the Cabazon Wind Energy Center near Cabazon, California. Cabazon Wind is an existing renewable resource that has been in commercial operation since 1999. SCE purchased the output of the facility through December 2014. At the expiration of SCE’s contract, Cabazon Wind entered into new interconnection and generation agreements with CAISO and SCE. The developer completed the implementation of the transition to the Electric Utility as of January 1, 2015. Delivery under the PPA commenced on January 1, 2015. The project is expected to generate 71,200 MWh of renewable energy per year with an all-in price for energy, capacity and environmental attributes of $59.30 per MWh over the term of the agreement. In 2018, after it was acquired by GlidePath Power Solutions, FPL Energy Cabazon Wind, LLC changed its name to GPS Cabazon Wind, LLC. On September 1, 2023, Salka Cabazon HoldCo LLC purchased the GPS Cabazon Wind project and assumed the remaining term of the Agreement.

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

On July 16, 2015, the Electric Utility entered into a 20-year PSA with SCPPA for 25 MW of solar photovoltaic energy generated by sPower’s Antelope DSR Solar 1 PV Project in the City of Lancaster, California. The Electric Utility has a 50 percent share of the output from the project through SCPPA, which has a 50 MW PPA with sPower. The project became

11. COMMITMENTS (CONTINUED)

RENEWABLE PORTFOLIO STANDARD (RPS) (CONTINUED)

commercially operational on December 20, 2016. The Electric Utility's share of Antelope DSR Solar 1 is expected to generate approximately 71,000 MWh of renewable energy per year with an all-in price for energy, capacity and environmental attributes of $53.75 per MWh over the term of the agreement. In 2021, sPower merged with the AES Corporation, resulting in AES becoming the new parent company.

On January 15, 2021, the Electric Utility entered into a 20-year PSA with SCPPA for 10 MW for the first 5 years of the contract and 30 MW for the remaining 15 years of the contract of geothermal energy generated by Atlantica's Coso Geothermal project. The Electric Utility has partnered with the cities of Banning and Pasadena to share SCPPA's contracted capacity. The project began delivery on January 1, 2022. The Electric Utility's share of Coso Geothermal is expected to provide 87,500 MWh annually in the first 5 years of the term and 268,300 MWh in the remainder of the term at an all-in price for energy, capacity, Resource Adequacy, and environmental attributes of $69.00 per MWh over the term of the agreement.

On February 16, 2021, the Electric Utility entered into a 5-year SB 859 Purchase Agreement with Roseburg Forest Products Co for the remaining 0.5 MW of SB 859 compliance. The Electric Utility has a 4.48 percent share of the output of the project along with SCPPA, Modesto Irrigation District, Sacramento Municipal Utility District, and Turlock Irrigation District, for a total capacity of 11 MW with Roseburg. The project began delivery on February 16, 2021. The price for the SB 859 compliant capacity is $46.00 per MWh over the term of the agreement.

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

LONG-TERM RESOURCE ADEQUACY PROCUREMENT

Resource Adequacy (RA) describes an electric utility's procurement of sufficient power supply capacity to serve its customers' projected electricity requirements plus an additional amount to be held in reserve for unanticipated circumstances (e.g., unplanned transmission or generation outages). This additional amount is referred to as a Planning Reserve Margin (PRM). Section 40 of the CAISO tariff governs the RA program requirements for load-serving entities, such as the Electric Utility, participating in CAISO markets. The CAISO tariff provides an option for local regulatory authorities of publicly-owned utilities to adopt their own PRM and RA program guidelines that meet certain criteria.

On May 23, 2006, the City Council adopted Resolution No. 21170, establishing its own RA program in response to the CAISO tariff requirements. This action preserved the Electric Utility's local control over its resource procurement. On June 5, 2012, the City Council adopted Resolution No. 22389, approving a revised RA program, which reflected current grid operational conditions, deleted obsolete provisions, and ensured efficient implementation while enhancing reliability. On August 18, 2020, the City Council adopted Resolution No. 23617, approving specific revisions to the Electric Utility's RA program to eliminate provisions that were no longer applicable and to better facilitate the ability to acquire less expensive RA resources. Resolution No. 23617 specifies that the Electric Utility shall maintain at least 15 percent PRM and be able to demonstrate that the utility has acquired enough system, local, and flexible RA to meet all CAISO annual and monthly RA filing deadlines.

Historically the Electric Utility has met most of its annual and monthly RA requirements by purchasing the capacity attributes from generation resources under long-term power purchase agreements (PPAs). This strategy has typically worked for meeting monthly RA requirements during the winter, since the Electric Utility rarely exhibits a peak load more than 300 MW from November through March. However, the Electric Utility has typically needed to buy additional merchant RA for non-winter months, with most of this need occurring during July, August and September. Additionally, this need has grown over time as the utility has contracted for more variable renewable wind and solar resources, because these variable resources don't provide the same amounts of qualifying RA as either firm baseload resources, dispatchable natural gas generation assets, or dispatchable battery energy storage assets. Given the Electric Utility's need for increasing amounts of RA, coupled with the recent increasing RA cost pressures and the anticipated exit from the Intermountain Power Project, it is critically important that the utility negotiate and secure additional long-term cost-effective RA contracts.

11. COMMITMENTS (CONTINUED)

LONG-TERM RESOURCE ADEQUACY PROCUREMENT (CONTINUED)

Long-term RA agreements with expected delivery:

Supplier	Type	Maximum Contract	Expected Delivery Date	Capacity Delivery No Later Than	Contract Term In Years
Vesi 15, LLC	Battery Storage	80.0 MW of RA	01/15/2026	03/15/2026	15
Baldy Mesa C, LLC	Battery Storage	50.0 MW of RA	03/01/2027	09/01/2027	15
Total		130.0 MW of RA			

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

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

CAP-AND-TRADE PROGRAM

Assembly Bill (AB) 32, enacted in 2006, mandated that the California Air Resources Board (CARB) develop regulations for the reduction of greenhouse gas (GHG) emissions to the 1990 levels by the year 2020. Subsequently, SB 32, enacted in 2016, extended the requirements of AB 32 and codified that it was the State’s goal to reduce GHG emissions to 40% below 1990 levels by the year 2020. AB 398 was then enacted in 2017 clarifying that it was the State legislature’s intent to continue the Cap-and-Trade Program and regulations until 2030. In January 2013, emission compliance obligations developed by CARB began under the Cap-and-Trade Program (Program). This Program requires electric utilities to have GHG allowances on an annual basis to offset GHG emissions associated with generating electricity. To ease the transition and mitigate the rate impacts to retail customers, CARB will allocate certain amounts of GHG allowances at no cost to electrical distribution utilities. The Electric Utility’s free allocation of GHG allowances is expected to be sufficient to meet the Electric Utility’s direct GHG compliance obligations.

At times, the Electric Utility may have allocated allowances in excess of its compliance obligations that can be sold into the CARB quarterly auctions. In fiscal years ended June 30, 2025 and 2024, the Electric Utility received $15,624 and $15,683, respectively, in proceeds related to the sale of the GHG allowances, which are included on the Statements of Revenues, Expenses and Changes in Net Position as other operating revenue. The Electric Utility has established a restricted Regulatory Requirement reserve to comply with regulatory restrictions and governing requirements related to the use of the GHG proceeds. The available funds are to be utilized for qualifying projects, consistent with the goals of AB 32 to benefit the retail ratepayers. The balance in the Regulatory Requirement reserve was $35,859 and $29,845 as of June 30, 2025 and 2024, respectively.

The Electric Utility also purchases GHG allowances, which can be used in future periods for GHG compliance regulations. The balance of purchased GHG allowances was $1,313 and $1,464 as of June 30, 2025 and 2024, and is recorded as inventory on the Statements of Net Position.

LOW CARBON FUEL STANDARD PROGRAM

AB 32, enacted in 2006, mandated that the California Air Resources Board (CARB) develop regulations for the reduction of greenhouse gas (GHG) emissions to the 1990 levels by the year 2020. Subsequently, SB 32, enacted in 2016, extended the requirements of AB 32 and codified that it was the State’s goal to reduce GHG emissions to 40% below 1990 levels by the year 2020. Similar to the Cap-and-Trade Program, the Low Carbon Fuel Standard (LCFS) Program is a key component of the market mechanisms authorized by these bills to achieve the State’s GHG emissions reduction goals. The LCFS regulation was initiated in 2009 and approved in 2010 by CARB. The program then underwent some litigation in the State of California and the regulation was re-adopted in 2015 with modifications and went into effect in 2016. LCFS seeks to reduce the carbon intensity (CI) of fuels used for transportation by establishing an annual CI target. Fuels that have a CI greater than the target have a compliance obligation and are required to turn in LCFS credits; fuels with a CI lower than the target may generate credits.

11. COMMITMENTS (CONTINUED)

LOW CARBON FUEL STANDARD PROGRAM (CONTINUED)

Electricity is considered a fuel subject to the program when it is used as a transportation fuel in electric vehicles. However, because the CI of electricity is substantially lower than the annual CI targets under the program, electricity is a fuel that generates LCFS credits and participation in the Program is voluntary. The City opted into the LCFS program in March 2018 and began generating LCFS credits for the first quarter of 2018. These credits are associated with two sources – unmetered electricity used to charge residents' electric vehicles at their homes (residential base credits) and from electric forklifts charging at private businesses (forklift credits). CARB calculates the credits that the Electric Utility receives and the Electric Utility submits reports quarterly to receive the credits.

The LCFS regulation was amended in 2018 and required that electric utilities that have opted into the LCFS Program participate in and manage a statewide point-of-sale rebate program for new electric vehicles. This program is called the California Clean Fuel Reward Program (CFR) and the City joined the program in May 2020. To fund the program, electric utilities are required to contribute proceeds received from the sales of residential base credits beginning with the credits the Electric Utility received in Q4 2019 (generated from electricity used for transportation in Q2 2019). Residential base credits the Electric Utility received prior to that time are not subject to the contribution requirements. Additionally, a "start-up" contribution from proceeds was required to be submitted by January 31, 2021. After the initial deposit of funds in November 2020, deposits to the CFR program are required by March 31 annually.

In November 2024, CARB adopted amendments to the LCFS regulation that went into effect on July 1, 2025. Under the new amendments, the CFR program will provide point-of-purchase rebates for new and/or used commercial medium- or heavy-duty electric vehicles rather than new light-duty electric vehicles. Additionally, the Electric Utility has been reclassified as a small publicly-owned utility and will no longer have an obligation to contribute funds to the CFR program, although its customers are still eligible to participate in the program. The approved amendments also included changes to the list of preapproved projects for holdback credits and no longer provides credits for electric forklift charging to electric utilities.

In fiscal years ended June 30, 2025 and 2024, the Electric Utility's proceeds from the sale of LCFS credits was $1,514 and $874, respectively. These proceeds are included on the Statements of Revenues, Expenses and Changes in Net Position as other operating revenue. The Electric Utility has established a restricted Regulatory Requirement reserve to comply with regulatory restrictions and governing requirements related to the use of the LCFS proceeds. The available funds are to be utilized for qualifying programs that support the Electric Utility's customers who are existing and future electric vehicle owners. Total expenses for qualifying programs as of June 30, 2025 and 2024 was $178 and $356, respectively. The balance in the Regulatory Requirement reserve as of June 30, 2025 and 2024 was $5,902 and $4,415, respectively.

CONSTRUCTION COMMITMENTS

As of June 30, 2025, the Electric Utility had commitments (encumbrances) of approximately $90,662 with respect to ongoing capital projects, of which $66,345 is expected to be funded by bonds, $24,317 to be funded by unrestricted cash reserves, and $0 to be funded by restricted cash reserves.

FORWARD PURCHASE/SALE AGREEMENTS

In order to meet seasonal energy needs and summer peaking requirements, the Electric Utility contracts on a monthly and/or quarterly basis for the purchase or sale of natural gas, electricity and/or capacity products on a one to four year forward time horizon. As of June 30, 2025, the Electric Utility has net natural gas and electricity commitments for fiscal year 2026 and thereafter of approximately $82,091, with a market value of $70,486. It should be noted that the market value can and typically does change on a daily basis.

12. LITIGATION

The Electric Utility is a defendant in various lawsuits arising in the normal course of business. Present lawsuits and other claims against the Electric Utility are incidental to the ordinary course of operations of the Electric Utility and are largely covered by the City's self-insurance program. In the opinion of management and the City Attorney, such claims and litigation will not have a materially adverse effect upon the financial position or results of operation of the Electric Utility. Contractual and litigation matters of the Electric Utility relating to SONGS are contained in Note 10.

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

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

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

On May 17, 2021, the City and the Paradas entered into a conditional settlement agreement. This settlement was conditioned on: (1) the Riverside City Council's placement of a ballot measure on City ballots in November 2021 to approve the City's General Fund Transfer practices as a general tax ("Ballot Measure"); and (2) voter approval of the Ballot Measure. The Riverside City Council placed the Ballot Measure on the ballot for the November 2, 2021 election. The Parties stayed the Parada lawsuit until certification of the results of the Ballot Measure. If voters approved the Ballot Measure, the City would refund to customers of its electric utility an amount equal to $24 million less the amount awarded to Plaintiffs' counsel in fees, paid over a five year period beginning no later than February 1, 2022. If voters did not approve the Ballot Measure, this litigation would then resume.

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

The election was held on November 2, 2021, and the Measure C was approved by voters, with 54.52% voting in favor.

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

12. LITIGATION (CONTINUED)

On May 12, 2022, the City and the Paradas amended the May 17, 2021 Settlement Agreement, with the following additional terms: (a) City agreed to start making refunds to ratepayers by October 1, 2022; (b) if the City prevailed in the appeal of the trial court's decision in the RAIT lawsuit, no additional refund would be due to the ratepayers; (c) if the City did not prevail in the appeal of the trial court's decision in the RAIT lawsuit, an additional refund would be implemented in the amount of $705,882 per month, from November, 2021 up to when the City either (i) sets new electric rates; (ii) voters approve a valid ballot measure for the GFT or (iii) the City otherwise stops collecting the electric GFT. The Parada lawsuit was dismissed on May 13, 2022.

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

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

13. LEASES AND SUBSCRIPTION-BASED INFORMATION TECHNOLOGY ARRANGEMENTS

LEASES PAYABLE

Leases are financings of the right-to-use an underlying asset and a lessee is required to recognize a lease liability and an intangible lease asset.

The Electric Utility had 26 and 21 leases as Lessee for the use of land, buildings and various pieces of machinery and equipment for the years ended June 30, 2025 and 2024, respectively. The Electric Utility is required to make principal and interest payments for these leases through fiscal year 2030. An initial lease liability was recorded in the amount of $625. As of June 30, 2025 and 2024, the value of the lease liability was $573 and $294, respectively. The leases had an interest rate of 0.52% to 2.80% and 0.52% to 2.50% for fiscal years ended June 30, 2025 and 2024, respectively.

The value of the lease assets was $1,119 and $613, with accumulated amortization of $506 and $326, for the fiscal years ended June 30, 2025 and 2024, respectively, as shown on the Asset Class activities tables found below.

	Amount of Lease Assets by Major Classes of Underlying Asset as of June 30, 2025	
Asset Class	**Lease Asset Value**	**Accumulated Amortization**
Land	$ 473	$ (55)
Building - Intangible	348	(297)
Machinery and Equipment	298	(154)
Total	$ 1,119	$ (506)

	Amount of Lease Assets by Major Classes of Underlying Asset as of June 30, 2024	
Asset Class	**Lease Asset Value**	**Accumulated Amortization**
Building - Intangible	$ 348	$ (223)
Machinery and Equipment	265	(103)
Total	$ 613	$ (326)

The following is a summary of changes in leases liability during the fiscal years ended June 30, 2025 and 2024:

	Balance As of 6/30/2023	Additions	Reclass	Reductions	Balance As of 6/30/2024	Additions	Reclass	Reductions	Balance As of 6/30/2025	Due Within One Year
Lease Liability	$ 362	$ 123	$ -	$ (191)	$ 294	$ 518	$ -	$ (239)	$ 573	$ 190

13. LEASES AND SUBSCRIPTION-BASED INFORMATION TECHNOLOGY ARRANGEMENTS (CONTINUED)

As of June 30, 2025, lease liability principal and interest payments consist of the following:

Fiscal Year	Principal Payments	Interest Payments	Total Payments
2026	$ 190	$ 12	$ 202
2027	126	9	135
2028	129	5	134
2029	126	2	128
2030	2	-	2
Total	$ 573	$ 28	$ 601

As of June 30, 2024, lease liability principal and interest payments consist of the following:

Fiscal Year	Principal Payments	Interest Payments	Total Payments
2025	$ 132	$ 3	$ 135
2026	92	2	94
2027	25	2	27
2028	25	1	26
2029	20	-	20
Total	$ 294	$ 8	$ 302

LEASES RECEIVABLE

Leases are financings of the right-to-use an underlying asset and a lessor is required to recognize a lease receivable and a deferred inflow of resources.

The Electric Utility had 12 and 11 leases as a Lessor for the use of various pieces of building and equipment for the fiscal years ended June 30, 2025 and 2024, respectively. At June 30, 2025 and 2024, the terms of these leases range from 5 to 30 years and 6 to 30 years, respectively, beginning on the contract commencement date. For the fiscal years ended June 30, 2025 and 2024, the value of the lease receivables was $11,232 and $12,412, respectively, with interest rates consistently ranging from 1.24% to 3.23%. As of June 30, 2025 and 2024, the value of the deferred inflow of resources was $10,224 and $11,741, with recognized lease revenue of $1,626 and $1,645, respectively.

As of June 30, 2025, lease receivable principal and interest payments consist of the following:

Fiscal Year	Principal Payments	Interest Payments	Total Payments
2026	$ 1,478	$ 216	$ 1,694
2027	1,644	183	1,827
2028	1,403	150	1,553
2029	1,024	120	1,144
2030	738	102	840
2031-2035	2,966	299	3,265
2036-2040	1,849	85	1,934
2041-2045	130	1	131
Total	$ 11,232	$ 1,156	$ 12,388

13. LEASES AND SUBSCRIPTION-BASED INFORMATION TECHNOLOGY ARRANGEMENTS (CONTINUED)

LEASES RECEIVABLE (CONTINUED)

As of June 30, 2024, lease receivable principal and interest payments consist of the following:

Fiscal Year	Principal Payments	Interest Payments	Total Payments
2025	$ 1,343	$ 182	$ 1,525
2026	1,506	166	1,672
2027	1,657	147	1,804
2028	1,401	129	1,530
2029	1,008	114	1,122
2030-2034	3,165	350	3,515
2035-2039	1,906	118	2,024
2040-2044	426	5	431
Total	$ 12,412	$ 1,211	$ 13,623

SUBSCRIPTION-BASED INFORMATION TECHNOLOGY ARRANGEMENTS PAYABLE

The Electric Utility had 2 and 4 subscription-based information technology arrangements (SBITA) for the use of various software for the fiscal years ended June 30, 2025 and 2024, respectively. The Electric Utility is required to make principal and interest payments for the leases through fiscal year 2026. An initial lease liability was recorded in the amount of $32. As of June 30, 2025, and 2024, the value of the subscription liability was $46 and $96, with an interest rate of 2.50% and 0.52% to 2.50%, respectively. As of June 30, 2025 and 2024, the value of the subscription assets was $135 and $231, with accumulated amortization of $81 and $108, respectively.

As of June 30, 2025 and 2024, the Asset Class activities tables were as follows:

	Amount of SBITA Assets by Major Classes of Underlying Asset as of June 30, 2025	
Asset Class	SBITA Asset Value	Accumulated Amortization
Software	$ 135	$ (81)
Total	$ 135	$ (81)

	Amount of SBITA Assets by Major Classes of Underlying Asset as of June 30, 2024	
Asset Class	SBITA Asset Value	Accumulated Amortization
Software	$ 231	$ (108)
Total	$ 231	$ (108)

13. LEASES AND SUBSCRIPTION-BASED INFORMATION TECHNOLOGY ARRANGEMENTS (CONTINUED)

SUBSCRIPTION-BASED INFORMATION TECHNOLOGY ARRANGEMENTS PAYABLE (CONTINUED)

The following is a summary of changes in SBITA liability during the fiscal years ended June 30, 2025 and 2024:

	Balance As of 6/30/2023	Additions	Reclass	Reductions	Balance As of 6/30/2024	Additions	Reclass	Reductions	Balance As of 6/30/2025	Due Within One Year
SBITA Liability	$ 49	$ 134	$ -	$ (87)	$ 96	$ -	$ -	$ (50)	$ 46	$ 46

As of June 30, 2025, SBITA liability principal and interest payments consist of the following:

Fiscal Year	Principal	Interest	Total Payments
2026	$ 46	$ 1	$ 47
Total	**$ 46**	$ 1	**$ 47**

As of June 30, 2024, SBITA liability principal and interest payments consist of the following

Fiscal Year	Principal	Interest	Total Payments
2025	$ 50	$ 1	$ 51
2026	46	1	47
Total	**$ 96**	$ 2	**$ 98**

14. RESTATEMENT OF BEGINNING NET POSITION

A restatement was recorded to decrease the Electric Utility's net position, including the Public Benefit Programs. The restatement reflects corrections to construction in progress of $(690), accumulated depreciation related to utility plant of $(592), and customer deposits of $909.

The effect of the restatement is shown in the table below:

	June 30, 2023 as Previously Reported	Error Correction	June 30, 2023 as Restated
Net Position	$ 503,352	$ (373)	$ 502,979

ELECTRIC UTILITY
SCHEDULE OF PROPORTIONATE SHARE OF THE NET PENSION LIABILITY
AS OF JUNE 30, FOR THE LAST TEN FISCAL YEARS (1)
(amounts expressed in thousands)

Reporting period	2025	2024	2023	2022	2021
Measurement period	**2024**	**2023**	**2022**	**2021**	**2020**
Electric Utility's Proportion of the Net Pension Liability	28.27%	28.53%	29.42%	29.56%	32.68%
Electric Utility's Proportionate Share of the Net Pension Liability	$ 52,913	$ 44,227	$ 38,748	$ (26,219)	$ 39,233
Electric Utility's Covered Payroll	$ 44,467	$ 40,566	$ 38,265	$ 38,794	$ 42,966
Electric Utility's Proportionate Share of the Net Pension Liability as a Percentage of Covered Payroll	118.99%	109.03%	101.26%	-67.59%	91.31%
Electric Utility's Proportionate Share of the Fiduciary Net Position as a Percentage of the Electric Utility's Total Pension Liability	89.53%	90.73%	91.80%	105.72%	91.95%

Notes to Schedule:

Benefit Changes:
There were no changes in benefits.

Changes in Assumptions:
From fiscal year June 30, 2015 to June 30, 2016:
GASB 68, paragraph 68 states that the long-term expected rate of return should be determined net of pension plan investment expense but without reduction for pension plan administrative expense. The discount rate of 7.50% used for the June 30, 2014 measurement date was net of administrative expenses. The discount rate of 7.65% used for the June 30, 2015 measurement date is without reduction of pension plan administrative expense.
From fiscal year June 30, 2016 to June 30, 2017:
There were no changes in assumptions.
From fiscal year June 30, 2017 to June 30, 2018:
The discount rate was reduced from 7.65% to 7.15%.
From fiscal year June 30, 2018 to June 30, 2022:
There were no significant changes in assumptions.
From fiscal year June 30, 2022 to June 30, 2023:
The discount rate and long-term rate of return decreased from 7.15% to 6.90% and the inflation rate decreased from 2.50% to 2.30%.
From fiscal year June 30, 2023 to June 30, 2024:
There were no significant changes in assumptions.
From fiscal year June 30, 2024 to June 30, 2025:
There were no significant changes in assumptions.

ELECTRIC UTILITY
SCHEDULE OF PROPORTIONATE SHARE OF THE NET PENSION LIABILITY (CONTINUED)
AS OF JUNE 30, FOR THE LAST TEN FISCAL YEARS (1)
(amounts expressed in thousands)

Reporting period	**2020**	**2019**	**2018**	**2017**	**2016**
Fiscal Year Ended	**2019**	**2018**	**2017**	**2016**	**2015**
Electric Utility's Proportion of the Net Pension Liability	30.73%	30.32%	32.04%	31.08%	31.96%
Electric Utility's Proportionate Share of the Net Pension Liability	$ 89,792	$ 84,468	$ 108,886	$ 96,193	$ 77,907
Electric Utility's Covered Payroll	$ 39,605	$ 36,976	$ 37,686	$ 36,834	$ 35,437
Electric Utility's Proportionate Share of the Net Pension Liability as a Percentage of Covered Payroll	226.72%	228.44%	288.93%	261.15%	219.85%
Electric Utility's Proportionate Share of the Fiduciary Net Position as a Percentage of the Electric Utility's Total Pension Liability	79.57%	79.64%	75.23%	75.47%	79.93%

Notes to Schedule:

Benefit Changes:
There were no changes in benefits.

Changes in Assumptions:
From fiscal year June 30, 2015 to June 30, 2016:
GASB 68, paragraph 68 states that the long-term expected rate of return should be determined net of pension plan investment expense but without reduction for pension plan administrative expense. The discount rate of 7.50% used for the June 30, 2014 measurement date was net of administrative expenses. The discount rate of 7.65% used for the June 30, 2015 measurement date is without reduction of pension plan administrative expense.
From fiscal year June 30, 2016 to June 30, 2017:
There were no changes in assumptions.
From fiscal year June 30, 2017 to June 30, 2018:
The discount rate was reduced from 7.65% to 7.15%.
From fiscal year June 30, 2018 to June 30, 2022:
There were no significant changes in assumptions.
From fiscal year June 30, 2022 to June 30, 2023:
The discount rate and long-term rate of return decreased from 7.15% to 6.90% and the inflation rate decreased from 2.50% to 2.30%.
From fiscal year June 30, 2023 to June 30, 2024:
There were no significant changes in assumptions.
From fiscal year June 30, 2024 to June 30, 2025:
There were no significant changes in assumptions.

ELECTRIC UTILITY
SCHEDULE OF CONTRIBUTIONS
AS OF JUNE 30, FOR THE LAST TEN FISCAL YEARS (1)
(amounts expressed in thousands)

	2025	2024	2023	2022	2021
Contractually Required Contribution (Actuarially Determined)	$ 7,769	$ 6,004 (6)	$ 8,316	$ 8,041	$ 7,768
Contributions in Relation to the Actuarially Determined Contributions	(7,769)	(6,004)	(8,316)	(8,041)	(7,768)
Contribution Deficiency (Excess)	$ -	$ -	$ -	$ -	$ -
Covered Payroll	$ 48,519	$ 44,467	$ 40,566	$ 38,265	$ 38,794
Contributions as a Percentage of Covered Payroll	16.01%	13.50%	20.50%	21.01%	20.02%

Notes to Schedule:

Valuation Date	6/30/2022	6/30/2021	6/30/2020	6/30/2019	6/30/2018
Methods and Assumptions Used to Determine Contribution Rates:					
Actuarial Cost Method	Entry Age	Entry Age	Entry Age	Entry Age	Entry Age
Amortization Method	(1)	(1)	(1)	(1)	(1)
Asset Valuation Method	Fair Value	Fair Value	Fair Value	Fair Value	Fair Value
Inflation	2.300%	2.300%	2.300%	2.500%	2.500%
Salary Increases	(2)	(2)	(2)	(2)	(2)
Investment Rate of Return	6.80% (3)	6.80% (3)	6.80% (3)	7.00% (3)	7.00% (3)
Retirement Age	(4)	(4)	(4)	(4)	(4)
Mortality	(5)	(5)	(5)	(5)	(5)

(1) Level percentage of payroll, closed
(2) Depending on age, service, and type of employment
(3) Net of pension plan investment expense, including inflation
(4) Classic: 50-67 and PEPRA: 52-67
(5) Mortality assumptions are based on mortality rates resulting from the most recent CalPERS Experience Study adopted by the CalPERS Board.
(6) This amount was projected in FY 2023-2024. Now that actual data is available, the number has been updated.

ELECTRIC UTILITY
SCHEDULE OF CONTRIBUTIONS (CONTINUED)
AS OF JUNE 30, FOR THE LAST TEN FISCAL YEARS (1)
(amounts expressed in thousands)

	2020	2019	2018	2017	2016
Contractually Required Contribution (Actuarially Determined)	$ 12,707	$ 10,598	$ 9,080	$ 8,635	$ 7,734
Contributions in Relation to the Actuarially Determined Contributions	(78,167)	(10,598)	(9,080)	(9,764)	(9,146)
Contribution Deficiency (Excess)	$ (65,460)	$ -	$ -	$ (1,128)	$ (1,411)
Covered Payroll	$ 42,966	$ 39,605	$ 36,976	$ 37,686	$ 36,834
Contributions as a Percentage of Covered Payroll	29.58%	26.76%	24.56%	22.91%	21.00%

Notes to Schedule:

Valuation Date	6/30/2017	6/30/2016	6/30/2015	6/30/2014	6/30/2013
Methods and Assumptions Used to Determine Contribution Rates:					
Actuarial Cost Method	Entry Age	Entry Age	Entry Age	Entry Age	Entry Age
Amortization Method	(1)	(1)	(1)	(1)	(1)
Asset Valuation Method	Fair Value	Fair Value	Fair Value	Fair Value	Fair Value
Inflation	2.625%	2.75%	2.75%	2.75%	2.75%
Salary Increases	(2)	(2)	(2)	(2)	(2)
Investment Rate of Return	7.25% (3)	7.375% (3)	7.50% (3)	7.50% (3)	7.50% (3)
Retirement Age	(4)	(4)	(4)	(4)	(4)
Mortality	(5)	(5)	(5)	(5)	(5)

(1) Level percentage of payroll, closed
(2) Depending on age, service, and type of employment
(3) Net of pension plan investment expense, including inflation
(4) Classic: 50-67 and PEPRA: 52-67
(5) Mortality assumptions are based on mortality rates resulting from the most recent CalPERS Experience Study adopted by the CalPERS Board.
(6) This amount was projected in FY 2023-2024. Now that actual data is available, the number has been updated.

ELECTRIC UTILITY
SCHEDULE OF CHANGES IN TOTAL OPEB LIABILITY AND RELATED RATIOS
AS OF JUNE 30, FOR THE LAST EIGHT FISCAL YEARS (1)
(amounts expressed in thousands)

Reporting period	**2025**	**2024**	**2023**	**2022**
Measurement period	**2024**	**2023**	**2022**	**2021**
Electric Utility's Proportion of the Net OPEB Liability	18.06%	18.68%	21.63%	24.45%
Electric Utility's Proportionate Share of the Net OPEB Liability	$ 10,807	$ 10,446	$ 9,837	$ 10,460
Electric Utility's Covered Payroll	$ 38,935	$ 39,099	$ 43,955	$ 48,238
Electric Utility's Proportionate Share of the Net OPEB Liability as a Percentage of Covered Payroll	27.76%	26.72%	22.38%	21.68%

Reporting period	**2021**	**2020**	**2019**	**2018**
Measurement period	**2020**	**2019**	**2018**	**2017**
Electric Utility's Proportion of the Net OPEB Liability	21.28%	21.41%	22.36%	22.52%
Electric Utility's Proportionate Share of the Net OPEB Liability	$ 11,126	$ 10,708	$ 8,572	$ 8,283
Electric Utility's Covered Payroll	$ 40,761	$ 39,816	$ 38,204	$ 38,477
Electric Utility's Proportionate Share of the Net OPEB Liability as a Percentage of Covered Payroll	27.30%	26.89%	22.44%	21.53%

(1) Historical information is required only for the measurement periods for which GASB 75 is applicable. Fiscal Year 2018 was the first year of implementation. Future years' information will be displayed up to 10 years as information becomes available.

Notes to Schedule:
Changes in assumptions: For the measurement period ending June 30, 2024, the discount rate was changed from 3.65 percent to 3.93 percent. There are no asset accumulated in a trust that meets the criteria of GASB codification P22.101 or P52.101 to pay related benefits for the OPEB plan.


RIVERSIDE
PUBLIC UTILITIES

ELECTRIC UTILITY:
KEY HISTORICAL OPERATING DATA

Fiscal Year	2024/25	2023/24	2022/23	2021/22	2020/21
POWER SUPPLY MEGAWATT-HOURS (MWH)					
Nuclear					
Palo Verde	102,300	103,000	101,500	101,100	99,800
Coal					
Intermountain Power	546,800	293,600	460,400	453,900	539,200
Hoover (Hydro)	24,900	23,600	22,900	28,000	30,600
Gas					
Springs	900	1,000	1,400	600	1,800
RERC	58,200	54,100	76,000	54,400	83,800
Clearwater	10,000	13,200	15,200	13,000	9,800
Renewable resources	813,500	923,000	937,500	978,700	938,100
Market purchases	711,300	786,800	625,000	653,200	559,200
Total	**2,267,900**	**2,198,300**	**2,239,900**	**2,282,900**	**2,262,300**
System peak megawatt (MW)	658.5	589.8	647.8	575.9	630.3
ELECTRIC USE					
Number of meters as of year end					
Residential	101,115	100,505	100,054	99,731	99,226
Commercial[3]	12,371	12,245	12,026	11,922	11,817
Industrial[3]	646	637	622	625	616
Other	48	49	49	50	52
Total	**114,180**	**113,436**	**112,751**	**112,328**	**111,711**
Millions of kilowatt-hours (kWh) sales					
Residential	781	710	786	759	783
Commercial[3]	438	427	440	443	430
Industrial[3]	927	916	920	923	891
Other	11	12	15	19	18
Subtotal	**2,157**	**2,065**	**2,161**	**2,144**	**2,122**
Wholesale[2]	-	-	14	2	-
Total	**2,157**	**2,065**	**2,175**	**2,146**	**2,122**
ELECTRIC FACTS					
Average annual kWh per residential customer	7,755	7,074	7,873	7,632	7,907
Average price (cents/kWh) per residential customer	$ 21.03	$ 19.58	$ 17.88	$ 17.71	$ 17.03
Debt service coverage ratio (DSC)[4,5,6,7]	3.20	2.31	2.01	2.03	1.99
Operating income as a percent of operating revenues	19.8 %	10.8 %	10.0 %	18.6 %	9.6 %
Employees[1]	473	473	473	473	468

1 Approved positions.

2 For fiscal years 20/21, 23/24 and 24/25, wholesale kWh was less than 1 million kWh. Increase in fiscal year 22/23 was due to a transmission constraint requiring the power the Electric Utility was scheduled to receive to be resold.

3 Changes in fiscal year 20/21 reflect reclassification of certain Industrial and Commercial accounts related to contract accounts.

4 Interest expense used to calculate DSC is net of federal subsidy on Build America Bonds.

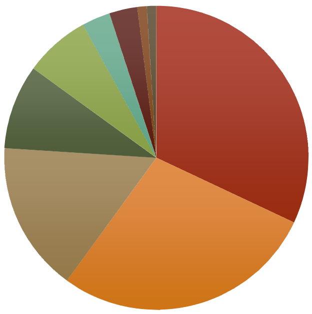
5 Does not include GASB 68 - Accounting and Financial Reporting for Pension non-cash adjustments of $9,584, $7,707, ($1,308), ($16,425), and $9,682 for fiscal years 24/25 through 20/21, respectively.

6 Does not include GASB 75 - Accounting and Financial Reporting for Post-employment Benefits Other than Pensions non-cash adjustments of $526, $474, $431, $530, and $183 for fiscal years 24/25 through 20/21, respectively.

7 Includes GASB 87 Leases net revenue adjustment of $373, $304, $247 and $134 for fiscal years 24/25 through 21/22, respectively.

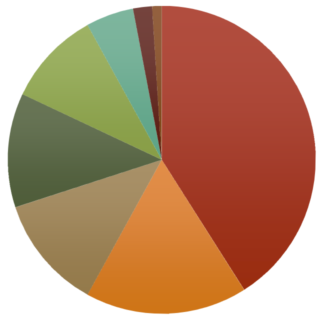
2024/2025 ELECTRIC REVENUE AND RESOURCES

SOURCE OF REVENUE



- Residential Sales 32¢
- Industrial Sales 28¢
- Commercial Sales 16¢
- Other Revenue 9¢
- Transmission Revenue 7¢
- Investment Income 3¢
- Public Benefit Programs 3¢
- Other Sales 1¢
- Use of Reserves 1¢

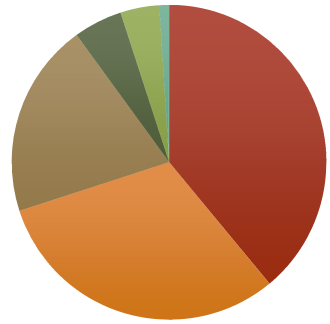
DISTRIBUTION OF REVENUE



- Production 41¢
- Distribution 17¢
- Transmission 12¢
- Debt Service 12¢
- Transfers to the City's General Fund* 10¢
- Additions & Replacements to the System 5¢
- Public Benefit Programs 2¢
- Unamortized Purchased Power 1¢

*Based on transfer of 11.5% of fiscal year 2023/2024 gross operating revenues including adjustments.

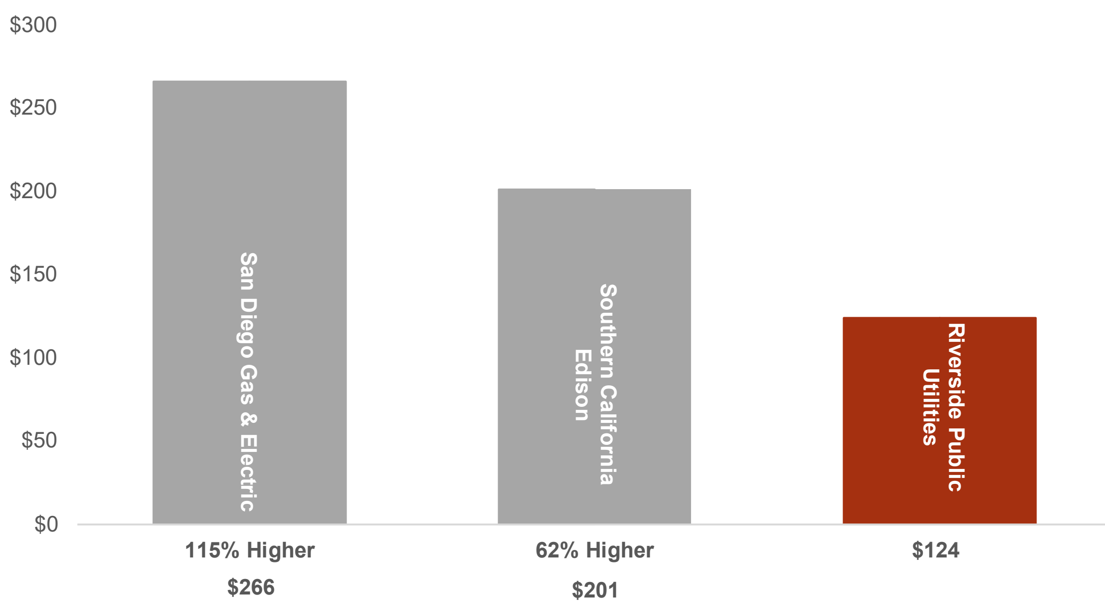
ENERGY RESOURCES**



- Renewables 39%
- Market Purchases 31%
- Coal 20%
- Nuclear 5%
- Gas 4%
- Hydropower 1%

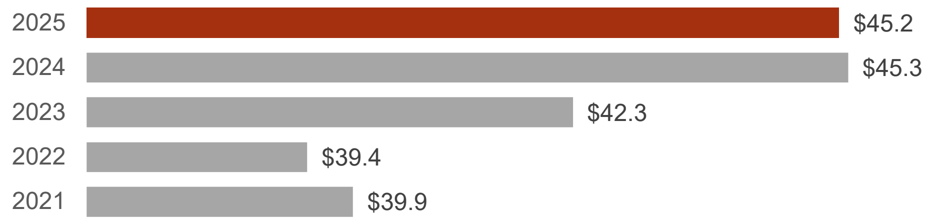
**Energy Resources are based on calendar year 2024 as filed with the California Energy Commission

ELECTRIC RATE COMPARISON - 600 KWH PER MONTH (AS OF JUNE 30, 2025)

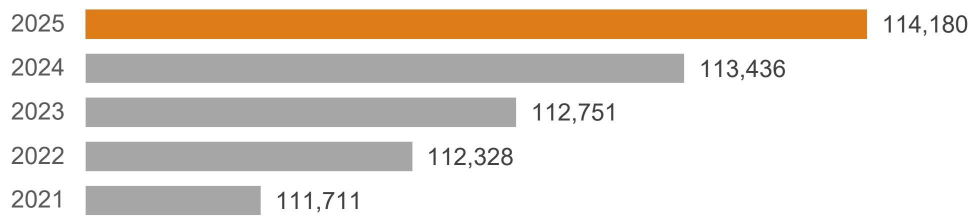


ELECTRIC KEY OPERATING INDICATORS

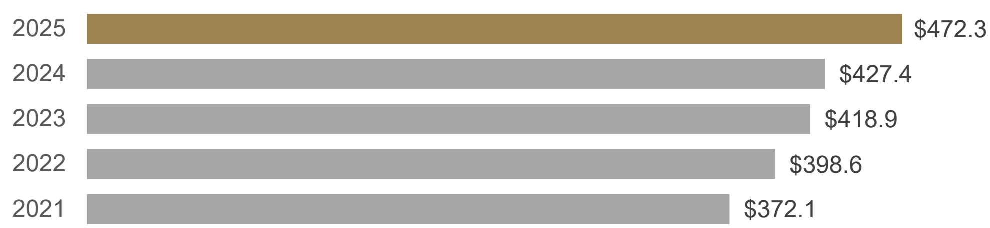
General Fund Transfer (In Millions)



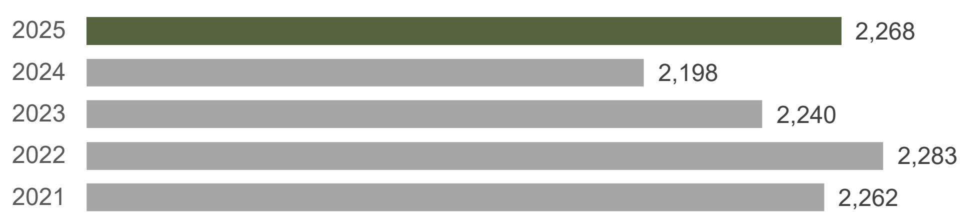
Number of Meters At Year End



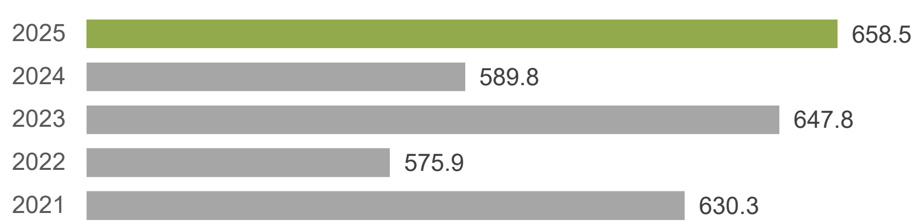
Total Operating Revenue (In Millions)



Production (In Million Kilowatt-Hours)



Peak Day Demand (In Megawatts)



ELECTRIC FACTS AND SYSTEM DATA

Established	1895
Service Area Population	320,278
City Area Size (square miles)	81.5

System Data

Transmission Lines (circuit miles)	99.2
Distribution Lines (circuit miles)	1,383
Number of Substations	16
2024-25 Peak Day (megawatts) Highest Single Hourly Use: 09/06/2024, 4pm, 109.7 degrees	658
Historical Peak (megawatts) Highest Single Hourly Use: 09/06/2024, 4pm, 109.7 degrees	658

Bond Ratings

Fitch Ratings	AA-
S & P Global Ratings	AA-

OUR WATER

RIVERSIDE PUBLIC UTILITIES

CliftonLarsonAllen LLP
CLAconnect.com

INDEPENDENT AUDITORS' REPORT

Honorable Mayor, Members of the City Council,
and Board of Public Utilities
City of Riverside
Riverside, California

Report on the Audit of the Financial Statements

Opinion

We have audited the accompanying financial statements of the Water Utility Enterprise Fund (Water Utility) of the City of Riverside, as of and for the years ended June 30, 2025 and 2024, and the related notes to the financial statements, as listed in the table of contents.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Water Fund of the City of Riverside, as of June 30, 2025 and 2024, and the changes in its financial position, and, its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

Basis for Opinion

We conducted our audits in accordance with auditing standards generally accepted in the United States of America (GAAS) and the standards applicable to financial audits contained in *Government Auditing Standards*, issued by the Comptroller General of the United States. Our responsibilities under those standards are further described in the *Auditors' Responsibilities for the Audit of the Financial Statements* section of our report. We are required to be independent of the Water Fund of the City of Riverside and to meet our other ethical responsibilities, in accordance with the relevant ethical requirements relating to our audits. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Emphasis of Matters

Restatement

As described in Note 12 to the financial statements, the Water Utility restated the beginning net position. Our opinions are not modified with respect to this matter.

As discussed in Note 1, the financial statements present only the Water Utility and do not purport to, and do not present fairly the financial position of the City of Riverside, California, as of June 30, 2025, the changes in its financial position, or, where applicable, its cash flows for the year then ended in accordance with accounting principles generally accepted in the United States of America. Our opinion is not modified with respect to this matter.

Honorable Mayor and
Members of the City Council
City of Riverside

Responsibilities of Management for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with accounting principles generally accepted in the United States of America, and for the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion. Reasonable assurance is a high level of assurance but is not absolute assurance and therefore is not a guarantee that an audit conducted in accordance with GAAS and *Government Auditing Standards* will always detect a material misstatement when it exists. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control. Misstatements are considered material if there is a substantial likelihood that, individually or in the aggregate, they would influence the judgment made by a reasonable user based on the financial statements.

In performing an audit in accordance with GAAS and *Government Auditing Standards*, we:

- Exercise professional judgment and maintain professional skepticism throughout the audit.

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, and design and perform audit procedures responsive to those risks. Such procedures include examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Water Utility's internal control. Accordingly, no such opinion is expressed.

- Evaluate the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluate the overall presentation of the financial statements.

We are required to communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit, significant audit findings, and certain internal control related matters that we identified during the audit.

Honorable Mayor and
Members of the City Council
City of Riverside

Required Supplementary Information

Accounting principles generally accepted in the United States of America require that the management's discussion and analysis, the schedule of proportionate share of the net pension liability, the schedule of contributions of the defined benefit plans, and the schedule of the Water Utility's proportionate share of the City's Total OPEB liability of the OPEB plan be presented to supplement the basic financial statements. Such information is the responsibility of management and, although not a part of the basic financial statements, is required by the Governmental Accounting Standards Board who considers it to be an essential part of financial reporting for placing the basic financial statements in an appropriate operational, economic, or historical context. We have applied certain limited procedures to the required supplementary information in accordance with GAAS, which consisted of inquiries of management about the methods of preparing the information and comparing the information for consistency with management's responses to our inquiries, the basic financial statements, and other knowledge we obtained during our audit of the basic financial statements. We do not express an opinion or provide any assurance on the information because the limited procedures do not provide us with sufficient evidence to express an opinion or provide any assurance.

Other Information

Management is responsible for the other information included in the annual report. The other information comprises the introductory section and operating statistical section but does not include the basic financial statements and our auditors' report thereon. Our opinion on the basic financial statements do not cover the other information, and we do not express an opinion or any form of assurance thereon.

In connection with our audit of the basic financial statements, our responsibility is to read the other information and consider whether a material inconsistency exists between the other information and the basic financial statements, or the other information otherwise appears to be materially misstated. If, based on the work performed, we conclude that an uncorrected material misstatement of the other information exists, we are required to describe it in our report.

Other Reporting Required by *Government Auditing Standards*

In accordance with *Government Auditing Standards*, we have also issued our report dated December 23, 2025, on our consideration of the City of Riverside's internal control over financial reporting and on our tests of its compliance with certain provisions of laws, regulations, contracts, and grant agreements and other matters. The purpose of that report is solely to describe the scope of our testing of internal control over financial reporting and compliance and the results of that testing, and not to provide an opinion on the effectiveness of the City of Riverside's internal control over financial reporting or on compliance. That report is an integral part of an audit performed in accordance with *Government Auditing Standards* in considering City of Riverside's internal control over financial reporting and compliance.

CliftonLarsonAllen LLP

CliftonLarsonAllen LLP

Irvine, California
December 23, 2025

WATER UTILITY:
MANAGEMENT'S DISCUSSION AND ANALYSIS

As management of Riverside Public Utilities, a department of the City of Riverside (the City), we offer the readers this narrative overview and analysis of the 2024-25 financial report for the periods ended June 30, 2025 and 2024 for Riverside's Water Utility (Water Utility), an enterprise fund of the City. We encourage readers to consider the information presented here in conjunction with additional information furnished in our financial statements, which begin on page 111 of this report. All amounts, unless otherwise indicated, are expressed in thousands of dollars.

FINANCIAL HIGHLIGHTS

- Retail sales, net of uncollectibles and recoveries, were $88,654 and $72,929 for the fiscal years ended June 30, 2025 and 2024, respectively. The increase reflects approved rate plan adjustments, higher customer consumption, and the implementation of an enhanced methodology for estimating unbilled revenue at year-end.
- Total revenue includes the accounting standard for fair market value adjustment of investments, which will continue to fluctuate based on market valuations. The adjustment was $1,786 and $1,115 in June 30, 2025 and 2024, respectively.
- Operating expense reflects a non-cash pension accounting standard adjustment, which will continue to fluctuate based on yearly actuarial information provided by the California Public Employees' Retirement System (CalPERS). The adjustment was $3,107 and $2,483 in June 30, 2025 and 2024, respectively.
- GASB Statement No. 101, *Compensated Absences* - For the year ended June 30, 2025, the financial statements include the adoption of GASB Statement No. 101. This Statement requires that liabilities for compensated absences be recognized for (1) leave that has not been used and (2) leave that has been used but not yet paid in cash or settled through noncash means. It also requires that a liability for certain types of compensated absences—including parental leave, military leave, and jury duty leave—not be recognized until the leave commences. This Statement also requires that a liability for specific types of compensated absences not be recognized until the leave is used. Further, this Statement establishes guidance for measuring a liability for leave that has not been used, generally using an employee's pay rate as of the date of the financial statements. Refer to Note 5 for additional information.
- A prior period restatement was made to adjust the beginning net position, primarily due to prior-period capital asset corrections identified during fiscal year 2024-2025, including the capitalization of assets previously placed in service with the related accumulated depreciation, and the reclassification of certain long-standing Construction in Progress balances that did not meet the capitalization criteria.

WATER UTILITY:
MANAGEMENT'S DISCUSSION AND ANALYSIS

OVERVIEW OF THE FINANCIAL STATEMENTS

This discussion and analysis is intended to serve as an introduction to the Water Utility's financial statements. The Water Utility is a department of the City, and its activities are recorded in a separate enterprise fund. These financial statements include only the activities for the Water Utility and provide comparative information for the last two fiscal years. Information on city-wide financial results is available in the City's Annual Comprehensive Financial Report (ACFR).

The Water Utility's financial statements are comprised of two components: 1) financial statements and 2) notes to the financial statements. In addition, this report also contains other supplementary information to provide the reader with additional information about the Water Utility, including pension and other postemployment benefit plan information, statistical data, historical sales and operating activities, and other relevant information.

Included as part of the financial statements are three separate statements, which collectively provide an indication of the Water Utility's financial health.

The ***Statements of Net Position*** present information on all of the Water Utility's assets, liabilities, deferred inflows and outflows of resources and net position. The Statements of Net Position provide information about the nature and amount of the Water Utility's resources and obligations at a specific point in time.

The ***Statements of Revenues, Expenses and Changes in Net Position*** report all of the Water Utility's revenues and expenses for the periods shown.

The ***Statements of Cash Flows*** report the cash provided and used by operating activities, as well as other cash sources, such as investment income and debt financing. They also report other cash uses such as payments for bond principal and capital additions and improvements.

The ***Notes to the Financial Statements*** provide additional information that is essential to a full understanding of the data provided in the Water Utility's financial statements. The Notes to the Financial Statements can be found on pages 117 to 152 of this report.

WATER UTILITY FINANCIAL ANALYSIS

CONDENSED STATEMENTS OF NET POSITION

	2025	2024*	2023*
Current and other assets	$ 214,055	$ 208,821	$ 219,843
Capital assets	524,395	522,652	517,482
Deferred outflows of resources	14,025	15,230	16,990
Total assets and deferred outflows of resources	752,475	746,703	754,315
Long-term debt outstanding	258,551	266,133	277,159
Other liabilities	51,085	50,047	42,865
Deferred inflows of resources	100,838	103,504	104,262
Total liabilities and deferred inflows of resources	410,474	419,684	424,286
Net investment in capital assets	292,595	292,584	298,880
Restricted	15,241	14,804	12,478
Unrestricted	34,165	19,631	18,671
Total net position	$ 342,001	$ 327,019	$ 330,029

*As restated.

ASSETS AND DEFERRED OUTFLOWS OF RESOURCES

2025 compared to 2024 The Water Utility’s total assets and deferred outflows of resources were $752,475, reflecting an increase of $5,772 (0.8%), primarily due to the following:

- Current and other assets, comprised of restricted and unrestricted assets, had a net increase of $5,234, primarily due to an increase of $7,109 in unrestricted cash and cash equivalents from positive operating results, an increase of $3,199 in accounts receivable, and an increase of $1,199 in restricted cash and cash equivalents from the receipt of equipment lease proceeds. The increase was offset by a decrease of $9,072 in restricted cash and cash equivalents at fiscal agent for the funding of capital projects.
- Capital assets increased by $1,743 as a result of an increase in additions and improvements to the Water distribution infrastructure system to improve service and reliability to the Water Utility's customers, offset by an increase in current-year depreciation. Additional capital asset information can be found in the “Capital Assets and Debt Administration” section.
- Deferred outflows of resources decreased by $1,205, primarily due to a decrease of $841 in deferred outflows related to pension as a result of pension accounting standards, as well as a decrease of $281 in loss on refunding due to the amortization.

2024 compared to 2023 Total assets and deferred outflows of resources were $746,703, reflecting a decrease of $7,612 (1.0%), primarily due to the following:

- Current and other assets, comprised of restricted and unrestricted assets, had a net decrease of $11,022, primarily due to a decrease of $20,917 in restricted cash and cash equivalents at fiscal agent for the funding of capital projects. The decrease was offset by an increase of $4,258 in unrestricted cash and cash equivalents due to positive operating results, as well as an increase of $1,549 in leases receivable.
- Capital assets increased by $5,170 as a result of an increase in additions and improvements to the Water distribution infrastructure system to improve service and reliability to the Water Utility's customers, offset by an increase in current-year depreciation. Additional capital asset information can be found in the “Capital Assets and Debt Administration” section.
- Deferred outflows of resources decreased by $1,760, primarily due to a decrease of $1,450 in deferred outflows related to pension as a result of pension accounting standards, as well as a decrease of $276 in loss on refunding due to the amortization.

LIABILITIES AND DEFERRED INFLOWS OF RESOURCES

2025 compared to 2024 The Water Utility's total liabilities and deferred inflows of resources were $410,474, reflecting a decrease of $9,210 (2.2%), primarily due to the following:

- Long-term debt outstanding decreased by $7,582, primarily due to principal payments on revenue bonds, pension obligation bonds, and financed purchases. Additional debt information can be found in the "Capital Assets and Debt Administration" section.
- Other liabilities increased by $1,038, primarily due to an increase of $2,783 in net pension liability, a net increase of $433 in compensated absences, an increase of $354 in derivative instruments, and an increase of $172 in other postemployment benefits liability. The increase was offset by a decrease of $3,035 in accounts payable.
- Deferred inflows of resources decreased by $2,666, primarily due to a decrease of $1,658 related to GASB 87 lease adjustments, a decrease of $516 related to pension adjustments, which included the changes in assumptions, the differences between expected and actual experience, and the change in projected versus actual earnings on pension plan investments as determined by the plan actuary, and a decrease of $473 related to fair value adjustments.

2024 compared to 2023 Total liabilities and deferred inflows of resources were $419,684, reflecting a decrease of $4,602 (1.1%), primarily due to the following:

- Long-term debt outstanding decreased by $11,026, primarily due to principal payments on revenue bonds, pension obligation bonds, and financed purchases. Additional debt information can be found in the "Capital Assets and Debt Administration" section.
- Other liabilities increased by $7,182, primarily due to an increase of $4,226 in accounts payable, an increase of $1,601 in net pension liability, and an increase of $819 in customer deposits.
- Deferred inflows of resources decreased by $758, primarily due to a decrease of $569 in pension-related adjustments, which included the changes in assumptions, the differences between expected and actual experience, and the change in projected versus actual earnings on pension plan investments as determined by the plan actuary. There was also a decrease of $493 related to GASB 87 lease adjustments. The decrease was offset by an increase of $387 related to GASB 72 fair value adjustments.

NET POSITION

2025 compared to 2024 The Water Utility's total net position, which represents the difference between the Water Utility's total assets and deferred outflows of resources less total liabilities and deferred inflows of resources, was $342,001, reflecting an increase of $14,982 (4.6%).

- The largest portion of the Water Utility's total net position, which is its investment in capital assets of $292,595 (85.6%), had an increase of $11 from prior year. Investment in capital assets reflects the Water Utility's investment in source of supply, pumping, treatment, and transmission and distribution facilities, less any related outstanding debt used to acquire these assets (net investment in capital assets). Additional capital asset information can be found in the "Capital Assets and Debt Administration" section.
- The restricted portion of net position totaled $15,241 (4.5%), reflecting an increase of $437 and representing resources that are subject to external restrictions on how they may be used. The increase was primarily due to an increase in the restricted debt service reserve, as well as an increase of $217 in the unfunded accrued liability for employee retirement plan. The increase was offset by a decrease of $652 in the Water Conservation fund. Restricted net position is reserved for items, such as debt repayment and funds collected for Water Conservation Programs, and other legally restricted assets.
- The unrestricted portion of net position totaled $34,165 (9.9%), reflecting an increase of $14,534 from prior year, primarily attributable to corrections to construction in progress and accumulated depreciation related to the utility plant, as well as positive operating results. Unrestricted net position may be used to meet the Water Utility's ongoing operational needs and obligations to customers and creditors.

2024 compared to 2023 Total net position was $327,019, reflecting an decrease of $3,010 (0.9%).

- The largest portion of the Water Utility's total net position, which is its investment in capital assets of $292,584 (89.5%), had a decrease of $6,296 from prior year. Investment in capital assets reflects the Water Utility's investment in source of supply, pumping, treatment, and transmission and distribution facilities, less any related outstanding debt used to acquire these assets (net investment in capital assets). Additional capital asset information can be found in the "Capital Assets and Debt Administration" section.
- The restricted portion of net position totaled $14,804 (4.5%), reflecting an increase of $2,326 and representing resources that are subject to external restrictions on how they may be used. The increase was primarily due to an increase of $1,157 in the unfunded accrued liability for employee retirement plan, as well as an increase in the restricted debt service reserve. Restricted net position is reserved for items, such as debt repayment and funds collected for Water Conservation Programs, and other legally restricted assets.
- The unrestricted portion of net position totaled $19,631 (6.0%), reflecting an increase of $960 from prior year, primarily attributable to positive operating results and an increase in investment income. Unrestricted net position may be used to meet the Water Utility's ongoing operational needs and obligations to customers and creditors.

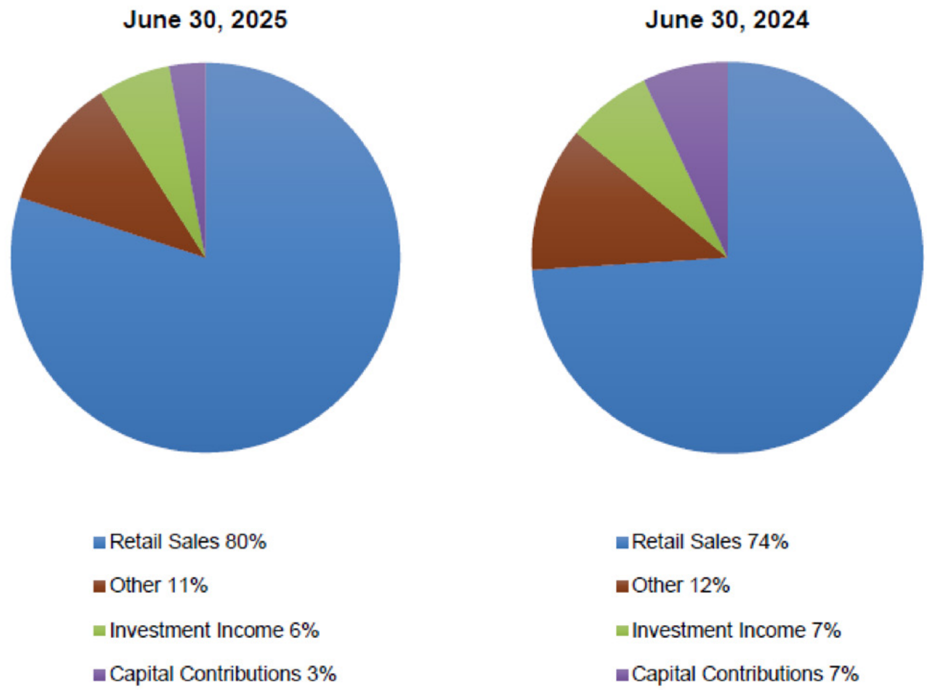
CONDENSED STATEMENTS OF CHANGES IN NET POSITION

	2025	2024*	2023*
Revenues:			
Retail sales, net	$ 88,654	$ 72,929	$ 69,854
Other revenues	12,159	11,560	12,297
Investment (loss) income	7,136	7,017	3,679
Capital contributions	2,823	6,532	8,290
Total revenues	110,772	98,038	94,120
Expenses:			
Operations and maintenance	50,135	46,679	42,738
Purchased energy	8,271	7,250	6,632
Depreciation	18,100	16,753	16,367
Amortization	13	15	20
Interest expense and fiscal charges	11,041	11,388	9,953
Total expenses	87,560	82,085	75,710
Transfers:			
Transfers to the City's general fund	(8,230)	(8,108)	(8,170)
Total Transfers	(8,230)	(8,108)	(8,170)
Changes in net position	14,982	7,845	10,240
Net position, July 1	327,019	330,029	322,304
Error correction	-	(10,855)	(2,515)
Net position, July 1, as restated	327,019	319,174	319,789
Net position, June 30	$ 342,001	$ 327,019	$ 330,029

*As restated.

WATER UTILITY:
MANAGEMENT'S DISCUSSION AND ANALYSIS

REVENUES BY SOURCES



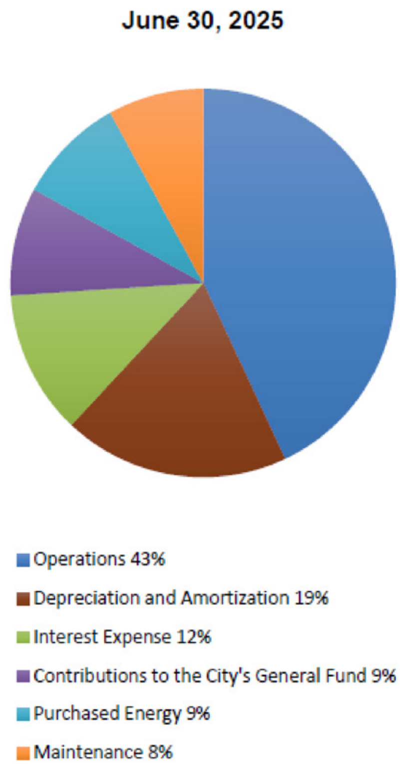
2025 compared to 2024 The Water Utility's total revenues of $110,772 increased by $12,734 (13.0%), primarily due to the following changes:

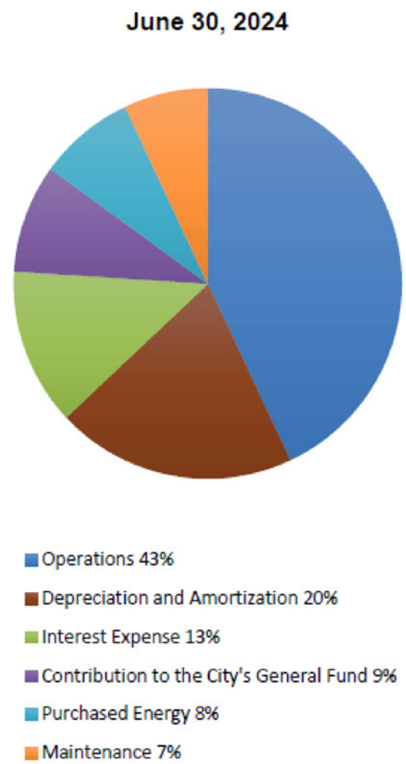
- Retail sales (residential, commercial, industrial, and others), net of uncollectibles and recoveries, totaled $88,654, an increase of $15,725 (21.6%) from prior fiscal year. Retail sales continue to be the primary revenue source for the Water Utility. The increase was due to approved rate plan adjustments, a 12.7% increase in customer consumption, and the implementation of an enhanced methodology for estimating unbilled revenue at year-end.
- Other revenues of $12,159 increased by $599 (5.2%), primarily due to an increase of $1,525 in settlement proceeds and liquidated damages, as well as an increase of $289 in gains on the sale of assets. The increase was offset by a decrease of $778 in Water Conservation Programs and a decrease of $658 in water conveyance sales.
- Capital contributions of $2,823 decreased by $3,709 (56.8%), primarily due to a decrease of $3,156 in contribution in aid compared to prior year.
- Investment income of $7,136 increased by $119 (1.7%), primarily due to a fair value adjustment of investments as well as positive investment results, which were offset by a decrease in interest earned on revenue bonds.

2024 compared to 2023 The Water Utility's total revenues of $98,038 increased by $3,918 (4.2%), primarily due to the following changes:

- Retail sales (residential, commercial, industrial, and others), net of uncollectibles and recoveries, totaled $72,929, an increase of $3,075 (4.4%) from prior fiscal year. Retail sales continue to be the primary revenue source for the Water Utility. The increase was due to a rate plan increase, offset by a 1.3% decrease in consumption.
- Other revenues of $11,560 decreased by $737 (6.0%), primarily due to a decrease of $704 in wholesale water sales compared to prior year.
- Capital contributions of $6,532 decreased by $1,758 (21.2%), primarily due to a decrease of $1,317 in contribution in aid.
- Investment income of $7,017 increased by $3,338 (90.7%), primarily due to a fair value adjustment of investments, additional interest earned on the 2022 Water Revenue bonds, and a higher overall interest rate in the current fiscal year.

EXPENSES BY SOURCES





2025 compared to 2024 The Water Utility's total expenses, excluding general fund transfer, were $87,560, an increase of $5,475 (6.7%). The increase was primarily due to the following:

- Operations and maintenance expenses of $50,135 increased by $3,456 (7.4%), primarily due to increases in personnel-related costs, a non-cash pension adjustment as a result of pension accounting standards, and increases in the cost of repairs and supplies.
- Purchased energy expenses of $8,271 increased by $1,021 (14.1%), primarily due to an increase in electricity costs.

2024 compared to 2023 The Water Utility's total expenses, excluding general fund transfer, were $82,085, an increase of $6,375 (8.4%). The increase was primarily due to the following:

- Operations and maintenance expenses of $46,679 increased by $3,941 (9.2%), primarily due to a non-cash pension adjustment as a result of pension accounting standards, and a restatement of net position related to certain reclassifications from Construction in Progress to Operations and Maintenance expense. Additional information regarding the restatement can be found in Note 12 of the accompanying financial statements.
- Purchased energy expenses of $7,250 increased by $618 (9.3%), primarily due to an increase in electricity costs.

TRANSFERS

Pursuant to the City's Charter and the voter approval of Measure A on June 4, 2013, the Water Utility may transfer up to 11.5 percent of prior year's gross operating revenues, including adjustments, to the City's general fund. The City uses these funds to help provide needed public services to the residents of the City, including police, fire, parks, libraries and other benefits. The Water Utility transferred $8,230 and $8,108 for 2025 and 2024, respectively, based on the gross operating revenue provisions in the City's Charter. For additional information, refer to Note 10.

CAPITAL ASSETS AND DEBT ADMINISTRATION

CAPITAL ASSETS

The Water Utility's investment in capital assets includes investments in source of supply, pumping, treatment, transmission and distribution facilities, land, intangibles, construction in progress, and lease and subscription assets, as well as general items such as office equipment, furniture, etc.

The following table summarizes the Water Utility's capital assets, net of accumulated depreciation, as of June 30:

	2025	2024*	2023*
Utility plant			
Source of supply	$ 55,503	$ 55,306	$ 54,223
Pumping	25,450	26,227	23,445
Treatment	22,603	24,358	25,652
Transmission and distribution	352,057	337,069	335,719
General	8,420	4,792	4,636
Land	20,870	20,870	20,841
Intangibles	10,881	10,773	10,883
Construction in progress	28,588	43,229	42,055
Total utility plant	524,372	522,624	517,454
Lease and subscription assets			
Machinery and equipment	23	20	11
Subscription-based information technology arrangements	-	8	17
Total capital assets	$ 524,395	$ 522,652	$ 517,482

*As restated.

2025 compared to 2024 The Water Utility's capital assets, net of accumulated depreciation, was $524,395, an increase of $1,743 (0.3%) from prior year. The increase resulted primarily from an increase in transmission and distribution assets. The Water Utility's significant capital projects include the following:

- $6,305 distribution pipelines, such as main replacements, distribution system facilities replacements, and system expansion.
- $2,478 in transmission pipelines, such as transmission mains.
- $1,984 in well projects, such as potable irrigation well replacements and facility rehabilitation.
- $1,699 in distribution facilities, such as pump station replacements and meters.
- $583 in water supply facilities, such as the Seven Oaks Dam conservation and recycled water facilities.

2024 compared to 2023 The Water Utility's capital assets, net of accumulated depreciation, was $522,652, an increase of $5,170 (1.0%) from prior year. The increase resulted primarily from an increase in pumping, transmission, and distribution assets. The Water Utility's significant capital projects include the following:

- $10,564 in water supply facilities, such as the Seven Oaks Dam conservation and recycled water facilities.
- $8,289 in distribution pipelines, such as main replacements, distribution system facilities replacements, and system expansion.
- $5,044 in transmission pipelines, such as transmission mains.
- $2,362 in well projects, such as potable irrigation well replacements and facility rehabilitation.
- $1,226 in distribution facilities, such as pump station replacements and meters.

Additional information regarding capital assets can be found in Note 3 of the accompanying financial statements.

DEBT ADMINISTRATION

The following table summarizes outstanding long-term debt as of June 30:

	2025	2024	2023
Revenue bonds	$ 226,890	$ 235,350	$ 243,300
Unamortized bond premium	19,630	20,815	21,994
Arbitrage liability	1,337	673	-
Pension obligation bonds	16,469	18,284	19,924
Contracts payable	931	931	933
Financed purchases	5,019	748	985
Less: Current portion of outstanding debt	(11,725)	(10,668)	(9,977)
Total	$ 258,551	$ 266,133	$ 277,159

The Water Utility's bond indentures require a minimum debt service coverage ratio, as defined by the bond covenants, of 1.25. The Water Utility's debt service coverage ratio was 2.51, 1.90 (as restated), and 1.95 at June 30, 2025, 2024, and 2023, respectively. The debt is backed by the revenues of the Water Utility. Debt service coverage ratio increased at June 30, 2025 due to an increase in total revenues compared to prior year, offset by increases in operating expenses as well as principal and interest payments on debt service. For additional information, see Note 4 of the accompanying financial statements and the Key Historical Operating Data section.

2025 compared to 2024 The Water Utility's long-term debt decreased by $7,582 (2.8%) to $258,551 as a result of current year principal payments and amortization of bond premiums, offset by an increase in arbitrage liability and financed purchases.

2024 compared to 2023 The Water Utility's long-term debt decreased by $11,026 (4.0%) to $266,133 as a result of current year principal payments and amortization of bond premiums, offset by an increase in arbitrage liability.

Additional information on the Water Utility's long-term debt can be found in Note 4 of the accompanying financial statements.

CREDIT RATINGS

The Water Utility maintains credit ratings of "AA+," "AA+" and "Aa2" from S&P Global Ratings (S&P), Fitch Ratings (Fitch) and Moody's, respectively. These ratings reflect the Water Utility's strong financial performance, advantageous water supply, investments in infrastructure and rate competitiveness, among many other factors.

WATER UTILITY:
MANAGEMENT'S DISCUSSION AND ANALYSIS

REGULATORY, LEGISLATIVE FACTORS, AND RATES

Utilities are faced with ongoing regulatory and legislative mandates enacted at the federal and state level that will have significant impacts on the operations of the Water Utility.

The State of California has experienced unprecedented drought conditions in recent years, resulting in severe impacts to California's water supplies and its ability to meet all of the demands for water in the State. The Water Utility is very fortunate as a water provider in California in that the Water Utility owns, operates and maintains its own water supply and is not typically dependent on imported water from outside sources. The Water Utility currently has sufficient water supplies to meet customer needs even during severe drought conditions.

The Water Utility continues to offer customers a wide variety of water conservation programs that help reduce their water usage and help the City meet State mandates and be more sustainable. These programs provide rebates for residents and businesses to help them save money by conserving water. In an effort to streamline and automate the rebate process, the City formed a partnership with Metropolitan Water District of Southern California to administer and process rebates for high-efficiency toilets, clothes washers, irrigation controllers and many other water-saving devices.

To further provide comprehensive resources and guidance as to how to implement water efficiency practices at residences and businesses, the Water Utility, in partnership with the City created the Street Park Turf Conversion and Demonstration Garden at the Janet Goeske Center. The Demonstration Garden allows residents and businesses to interact with water conservation materials and techniques that conserve water, elevate customer awareness, increase incentive program participation, provide educational opportunities and demonstrate water conservation best practices.

The Water Utility's long-range water supply planning includes significant contributions of conservation, water loss reduction and investments in projects to augment water supply portfolio, such as recycled water and Groundwater Basin recharge. The behavioral changes instituted through conservation and water use efficiency should have some permanent impact. Changes in landscape patterns and uses will have permanent and on-going impacts to water use. Continuing conservation measures could negatively impact the Water Utility revenues and has been addressed in the recent cost of service analysis conducted by the Water Utility.

During fiscal year 2024/25, RPU's water use efficiency programs have supported residents and business to save just over 8 million gallons of water. These savings are the result of the range of RPU's incentivization programs, which include high-efficiency clothes washers, toilets and weather-based irrigation controllers and the Smart Irrigation Program (SIP).

WATER CONSERVATION

On May 31, 2018, Governor Jerry Brown signed long-term water-use efficiency bills Senate Bill 606 and Assembly Bill 1668, known as "Making Conservation a California Way of Life," into law to establish a long-term foundation for water use efficiency and drought planning.

These bills required the Department of Water Resources to establish a regulatory framework for achieving long-term water use efficiency and address the challenges posed by climate change and the increasing frequency and severity of droughts in California. Under the new regulations, around 400 urban water suppliers will need to meet individualized water-use targets, among other performance standards and reporting requirements.

The "Making Conservation a Way of Life" regulatory framework represents a departure from the previous one-size-fits-all approach to water management in California, such as the mandatory 25% statewide water reductions ordered by Governor Jerry Brown during the 2012-2016 drought. The new regulation allows suppliers to consider local factors like climate, population, and landscaped areas, and were collaboratively developed with stakeholder input over the past six years. This regulation also promises to lessen the need for enacting emergency water-use reductions during drought episodes.

Under AB 1668 and the regulation, the City must set, meet and report water use objectives for its service area using a water budget-based approach by 2025. In total, four water use standards, including indoor residential use, outdoor residential use, commercial, industrial, and institutional dedicated irrigation meter use, and water loss, will be aggregated to calculate a water purveyor's unique efficient water use target. Final regulations were adopted in July 2024, with reporting beginning 2025. In addition, under SB 606, the City must conduct and submit an Annual Water Supply and Demand Assessment report starting in 2022 and a Drought Risk Assessment every five years as part of its Urban Water Management Plan.

The City of Riverside has been engaged with the development of the regulation since it was signed into law in 2018, participating in workshops, attending public hearings, and submitting formal comment letters during the rulemaking process. In preparation, the City has also calculated multiple compliance scenarios using conservative estimates to assess the City's performance for each of the Objective standards as they become more stringent through 2040.

Customer Engagement Efforts

RPU's Customer Engagement (CE) division assists both residential and commercial customers increase their water use efficiency through a variety of programs, incentives, rebates, and education. The CE team is responsible for several critical tasks to help the City comply with the new long-term water use efficiency regulations. These tasks include:

Residential Indoor/Outdoor Water Use: CE will continue to utilize existing water use efficiency programs and incentives to assist customers with their water efficiency projects. Additionally, RPU's long-standing Smart Irrigation Program is a direct installation program that helps customers identify outdoor water-saving opportunities and provides smart irrigation controllers paired with high-efficiency sprinkler nozzles. CE has also secured a two-year contract at no cost for a new water efficiency software called WaterView. This tool allows the CE team to support the creation of outreach campaigns to target inefficient water users and provide customer-appropriate level of assistance, rebates, and incentives. In the future, programs may be expanded, including potential new direct installation programs for various water saving devices.

CII Outdoor Water Use (Dedicated Irrigation Meters): For CII customers with Dedicated Irrigation Meters (DIMs), landscape irrigation water budgets will be generated and compared to actual irrigation water usage, providing tailored assistance for customers watering more than their landscape needs. The CE team anticipates expanding current landscape and irrigation incentive programs, targeting inefficient water users, and may consider offering a Landscape Optimization Service Program for this customer type.

CII Mixed Use Meters (MUMS): For commercial CII Mixed Use Meters (MUMs) with irrigated landscapes, Customer Engagement will identify mixed use meters that serve properties with a minimum of 0.5 acres of irrigated area. Per the new regulations, CE will implement in-lieu technologies, which will work in concert with the required Best Management Practices (BMPs). In-lieu technologies include measures, which are currently under consideration, such as hardware improvements, remote sensing, and other technologies to help CII customers with MUMs irrigate their landscapes more efficiently. BMPs include outreach, education, incentives, landscape measures, agency collaboration and operational enhancements, such as billing and data management.

RPU's Customer Engagement team will also offer customer education, landscape classes, and outreach to support the City's compliance with the new regulation. RPU will maintain its commitment to customer education through enhanced community engagement and expanded educational opportunities for local students.

WATER STANDARDS

The development of new and increasingly stringent drinking water regulations by the U.S. Environmental Protection Agency (USEPA) are significantly impacting water supply costs throughout the state and the nation. New chemical and biological contaminants are being discovered through more sophisticated research techniques and improved analytical methods. In addition, public health and environmental agencies are now evaluating how anthropogenic factors are impacting our water supplies. Pesticides, pharmaceuticals, and personal care products are being evaluated at trace levels, which can be orders of magnitude lower than what was achievable 20 years ago. As a result, water treatment costs are increasing as federal and state legislators and regulators try to balance public health risk with affordable water supply costs.

WATER UTILITY:
MANAGEMENT'S DISCUSSION AND ANALYSIS

On July 21, 2020, the USEPA published a final action to withdraw the Agency's 2011 regulatory determination to regulate perchlorate after finding that perchlorate did not occur with a frequency and at levels of public health concern within the meaning of the Safe Drinking Water Act, and that development of a regulation did not present a meaningful opportunity for health risk reduction for persons served by public water systems. On May 9, 2023, the U.S. Court of Appeals for the District of Columbia Circuit ordered the EPA to formulate a perchlorate MCL by 2027. Previous considerations for a Federal perchlorate MCL were almost 10 times higher than the State MCL, but staff will continue to monitor regulatory activities. The State of California began regulating perchlorate in 2007 with a MCL set at 6 parts per billion ("ppb") and a detection level for purposes of reporting (DLR) of 4 ppb. Beginning July 1, 2021, the DLR was lowered to 2 ppb and will be lowered to 1 ppb effective January 1, 2024. After data is collected at these lower DLR's evaluation of the perchlorate MCL, and possible need for reduction, will occur. A reduction in the perchlorate standard could impact the Water Utility's water supply costs.

Perfluorooctanoic acid (PFOA) and perfluorooctane sulfonic acid (PFOS) are fluorinated organic chemicals which are part of a family of compounds referred to as per- and polyfluoroalkyl substances (PFAS). PFAS are synthetic compounds that are water and lipid resistant and are useful for a variety of manufacturing processes and industrial applications. In May 2016, the USEPA issued a lifetime health advisory for PFOA and PFOS in drinking water of a combined level of 70 ppt. In February 2021, the USEPA determined to move forward with the process of implementing a national primary drinking water regulation for PFOA and PFOS. In March 2023, the USEPA issued health-based, non-enforceable Maximum Contaminant Level Goals and draft MCLs for six PFAS chemicals: PFOA, PFOS, Perfluorohexane sulfonic acid (PFHxS), Perfluorononanoic acid (PFNA), GenX chemicals, and Perfluorobutane sulfonic acid (PFBS). The following MCLs were adopted on April 10, 2024: PFOA at 4 ppt, PFOS at 4 ppt, and PFNA, PFHxS, PFBS and GenX regulated together as a Hazard index where the ratio of the chemicals when added together must be less than 1. The Hazard index established Health Based Water Concentrations for PFHxS of 10 ppt, PFNA at 10 ppt, GenX at 10 ppt, and PFBS at 2,000 ppt. The regulation requires water systems to complete initial monitoring by 2027, and reduce levels over the MCL by 2029. In addition, on April 19, 2024, the USEPA designated PFOA and PFOS as hazardous substances under CERCLA which would increase transparency and hold polluters accountable however, could also increase disposal costs for spent GAC or IX media used to remove PFAS.

With respect to California, in August 2019, the Division of Drinking Water (DDW) established Notification Levels (NLs) for PFOA and PFOS of 5.1 and 6.5 ppt, respectively, and in February 2020, DDW issued updated drinking water Response Levels (RLs) of 10 ppt for PFOA and 40 ppt for PFOS based on a running four-quarter average. On February 6, 2020, SWRCB tasked the Office of Environmental Health Hazard Assessment (OEHHA) to set advisory limits for perfluorohexane sulfonic acid (PFHxS), perfluorobutane sulfonic acid (PFBS), perfluorohexanoic acid (PFHxA), perfluoroheptanoic acid (PFHpA), perfluorononanoic acid (PFNA), perfluorodecanoic acid (PFDA), and 4,8-dioxia-3H-perfluorononanoic acid (ADONA), in addition to PFOS and PFOA. On March 5, 2020, PFBS was issued an NL of 500 ppt and an RL of 5000 ppt, by SWRCB. In June 2021, OEHHA released a draft PHG for PFOA and PFOS at 0.007 ppt and 1 ppt, respectively. Following OEHHA's March 2022 recommendations on PFHxS, DDW issued an NL of 3 ppt and an RL of 20 ppt in October 2023. On September 18, 2024, OEHHA recommended an NL of 1,000 ppt for PFHxA. In October 2025, DDW issued revised NLs for PFOA and PFOS, a revised RL for PFHxS, and a new NL and RL for PFHxA. The current levels are as follows:

PFAS	New NL (ng/L)	New RL (ng/L)
PFOA	4.0	10
PFOS	4.0	40
PFHxS	3.0	10
PFHxA	1,000	10,000

The City believes that PFAS have been in the groundwater basins from which the City draws water in very low concentrations for many years. Recent technological advances enabled water agencies to detect PFAS compounds at such low concentrations. The City's goal is to remain below the Notification Levels, which are lower than the Response Level. Many of the City's wells with detections of PFAS also extract water from the same aquifers that are contaminated by other known anthropogenic chemicals and are currently being treated by existing treatment facilities. Beginning fall 2019, the Board approved the expenditure of approximately $850,000 to test new treatment technologies, assess the feasibility of resurrecting an abandoned treatment plant to treat a well field with high levels of PFAS and develop a long-term water treatment strategy. Based on the results of this study, RPU identified three critical locations for new or augmented treatment facilities, including Palmyrita Treatment Plant, J.W. North Treatment Plant, and Palm Meadows Treatment Plant. These facilities will employ a combination of granular activated carbon (GAC), ion exchange (IX), and reverse osmosis (RO) to optimize treatment of PFAS and other contaminants. The design and construction management contract was awarded for the Palmyrita PFAS Water Treatment Plant, and the 90% design submittal has been received.

The Water Utility will continue to monitor the progress of the proposed standard changes and will advocate for standards that protect human health and are based on the best available science.

FIVE-YEAR WATER RATE PLAN

On September 19, 2023, the City Council approved a five-year Water Rate Plan, which includes system average annual rate increases. The first annual rate increase was effective October 1, 2023, with the following four years effective on July 1 of each year. The approved five-year Water Rate Plan includes annual reviews of the adopted rates by City Council. The system average rate increases are 6.5% each year of the five-year Water Rate Plan. The Water Rate Plan was designed to provide financial stability and correct the imbalance of costs versus revenue recovery.

REQUESTS FOR INFORMATION

This financial report is designed to provide a general overview of the Water Utility's finances. Questions concerning any information provided in this report or requests for additional financial information should be addressed to the Utilities Assistant General Manager – Finance and Administration, Riverside Public Utilities, 3750 University Avenue, 5th floor, Riverside, CA 92501. Additional financial information can also be obtained by visiting www.RiversideCA.gov/Utilities.

WATER UTILITY:
FINANCIAL STATEMENTS

STATEMENTS OF NET POSITION

ASSETS AND DEFERRED OUTFLOWS OF RESOURCES	June 30, 2025 (in thousands)	June 30, 2024
NON-CURRENT ASSETS:		
Capital assets:		
Utility plant, net of accumulated depreciation (Note 3)	$ 464,069	$ 447,680
Capital assets, not depreciated (Note 3)	60,303	74,944
Lease and subscription capital assets, net of amortization (Note 3 & 11)	23	28
Total capital assets	524,395	522,652
Restricted assets:		
Cash and cash investments at fiscal agent (Note 2)	2,835	1,840
Cash and cash equivalents at fiscal agent (Note 2)	25,483	34,555
Total non-current restricted assets	28,318	36,395
Other non-current assets:		
Regulatory assets	1,259	1,332
Leases receivable (Note 11)	89,107	88,722
Other long-term assets	1,014	-
Total other non-current assets	91,380	90,054
Total non-current assets:	644,093	649,101
CURRENT ASSETS:		
Unrestricted assets:		
Cash and cash equivalents (Note 2)	60,558	53,449
Accounts receivable, less allowance for doubtful accounts 2025 $831; 2024 $660	15,059	11,860
Accrued interest receivable	3,983	2,980
Leases receivable (Note 11)	952	847
Prepaid expenses	216	218
Total unrestricted current assets	80,768	69,354
Restricted assets:		
Cash and cash equivalents (Note 2)	10,445	9,246
Water Conservation Programs - cash and cash equivalents (Note 2)	3,124	3,747
Water Conservation Programs receivable	20	25
Total restricted current assets	13,589	13,018
Total current assets	94,357	82,372
Total assets	738,450	731,473
DEFERRED OUTFLOWS OF RESOURCES:		
Deferred outflows related to pension (Note 6)	9,297	10,138
Deferred outflows related to other postemployment benefits (Note 7)	527	610
Loss on refunding	4,201	4,482
Total deferred outflows of resources	14,025	15,230
Total assets and deferred outflows of resources	$ 752,475	$ 746,703

See accompanying notes to the financial statements

WATER UTILITY:
FINANCIAL STATEMENTS

STATEMENTS OF NET POSITION

NET POSITION, LIABILITIES AND DEFERRED INFLOWS OF RESOURCES	June 30, 2025 (in thousands)	June 30, 2024
NET POSITION:		
Net investment in capital assets	$ 292,595	$ 292,584
Restricted for:		
Debt service (Note 8)	10,800	9,928
Unfunded accrued liability	1,374	1,157
Water Conservation Programs	3,067	3,719
Unrestricted	34,165	19,631
Total net position	342,001	327,019
LONG-TERM OBLIGATIONS, LESS CURRENT PORTION (Note 4)	258,551	266,133
OTHER NON-CURRENT LIABILITIES:		
Compensated absences (Note 5)	1,452	643
Net pension liability (Note 6)	17,238	14,455
Other postemployment benefits liability (Note 7)	4,275	4,103
Derivative instruments (Note 4)	1,185	831
Regulatory liability	4,636	4,516
Lease liability (Note 11)	18	16
Total other non-current liabilities	28,804	24,564
CURRENT LIABILITIES PAYABLE FROM RESTRICTED ASSETS:		
Accrued interest payable	2,425	2,512
Water Conservation Programs payable	77	53
Current portion of long-term obligations (Note 4)	11,575	10,518
Total current liabilities payable from restricted assets	14,077	13,083
CURRENT LIABILITIES:		
Accounts payable and other accruals	5,104	8,139
Compensated absences (Note 5)	1,658	2,034
Customer deposits	1,099	1,853
Unearned revenue	58	55
Other postemployment benefits liability (Note 7)	129	162
Current portion of long-term obligations (Note 4)	150	150
Lease liability (Note 11)	6	5
SBITA liability (Note 11)	-	2
Total current liabilities	8,204	12,400
Total liabilities	309,636	316,180
DEFERRED INFLOWS OF RESOURCES:		
Deferred inflows related to pension (Note 6)	102	618
Deferred inflows related to other postemployment benefits (Note 7)	787	806
Changes in derivative values	110	583
Lease related items (Note 11)	99,839	101,497
Total deferred inflows of resources	100,838	103,504
Total net position, liabilities and deferred inflows of resources	$ 752,475	$ 746,703

See accompanying notes to the financial statements

WATER UTILITY:
FINANCIAL STATEMENTS

STATEMENTS OF REVENUES, EXPENSES AND CHANGES IN NET POSITION

	For the Fiscal Years Ended June 30, 2025	2024
	(in thousands)	
OPERATING REVENUES:		
Residential sales	$ 55,387	$ 45,969
Commercial sales	29,888	24,858
Other sales	3,797	2,266
Water conveyance revenue	3,033	3,691
Water Conservation Programs	205	983
Other operating revenue	3,774	3,659
Total operating revenues before uncollectibles	96,084	81,426
Estimated uncollectibles, net of bad debt recovery	(418)	(164)
Total operating revenues, net of uncollectibles	95,666	81,262
OPERATING EXPENSES:		
Operations	40,866	39,314
Maintenance	8,412	6,557
Purchased energy	8,271	7,250
Water conservation	857	808
Depreciation (Note 3)	18,100	16,753
Amortization (Note 3)	13	15
Total operating expenses	76,519	70,697
Operating income	19,147	10,565
NON-OPERATING REVENUES (EXPENSES):		
Investment (loss) income	7,136	7,017
Interest expense and fiscal charges	(11,041)	(11,388)
Gain on sale of assets	116	(173)
Other	5,031	3,400
Total non-operating revenues (expenses)	1,242	(1,144)
Income (loss) before capital contributions and transfers	20,389	9,421
Capital contributions	2,823	6,532
Transfers out - contributions to the City's general fund	(8,230)	(8,108)
Total capital contributions and transfers	(5,407)	(1,576)
Change in net position	14,982	7,845
NET POSITION, BEGINNING OF YEAR, AS PREVIOUSLY STATED	327,019	330,029
ERROR CORRECTION (Note 12)	-	(10,855)
NET POSITION, BEGINNING OF THE YEAR, AS RESTATED	327,019	319,174
NET POSITION, END OF YEAR	$ 342,001	$ 327,019

See accompanying notes to the financial statements

WATER UTILITY:
FINANCIAL STATEMENTS

STATEMENT OF CASH FLOWS

	For the Fiscal Years Ended June 30, 2025	2024
	(in thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
Cash received from customers and users	$ 91,721	$ 81,352
Cash paid to suppliers for goods and services	(39,321)	(31,075)
Cash paid to employees for services	(18,350)	(15,869)
Net cash provided (used) by operating activities	**34,050**	**34,408**
CASH FLOWS FROM NON-CAPITAL FINANCING ACTIVITIES:		
Transfers out - contributions to the City's general fund	(8,230)	(8,108)
Debt service payment on pension obligation bonds	(1,815)	(1,640)
(Increase) decrease in restricted arbitrage cash	(664)	(673)
Other non-operating receipts	2,886	1,274
Net cash provided (used) by non-capital financing activities	**(7,823)**	**(9,147)**
CASH FLOWS FROM CAPITAL AND RELATED FINANCING ACTIVITIES:		
Purchase of utility plant	(20,862)	(29,170)
Proceeds from the sale of utility plant	116	258
Proceeds from equipment lease purchase	4,814	-
Principal paid on long-term obligations	(8,340)	(8,188)
Interest paid on long-term obligations	(11,295)	(10,973)
Capital contributions	2,823	2,491
Lease and subscription payments	(8)	(15)
Net cash provided (used) by capital and related financing activities	**(32,752)**	**(45,597)**
CASH FLOWS FROM INVESTING ACTIVITIES:		
Proceeds from (purchase of) investment securities	(995)	(1,840)
Income (loss) from investments	6,133	6,016
Net cash provided (used) by investing activities	**5,138**	**4,176**
Net increase (decrease) in cash and cash equivalents	**(1,387)**	**(16,160)**
CASH AND CASH EQUIVALENTS, BEGINNING OF YEAR (including $47,548 and $67,966 at June 30, 2024 and June 30, 2023, respectively, reported in restricted accounts)	100,997	117,157
CASH AND CASH EQUIVALENTS, END OF YEAR (including $39,052 and $47,548 at June 30, 2025 and June 30, 2024, respectively, reported in restricted accounts)	$ 99,610	$ 100,997

See accompanying notes to the financial statements

WATER UTILITY:
FINANCIAL STATEMENTS

STATEMENT OF CASH FLOWS

	For the Fiscal Years Ended June 30, 2025	2024
	(in thousands)	
RECONCILIATION OF OPERATING INCOME TO NET CASH PROVIDED (USED) BY OPERATING ACTIVITIES:		
Operating income (loss)	19,147	10,565
Adjustments to reconcile operating income (loss) to net cash provided (used) by operating activities:		
Depreciation	18,100	16,753
Amortization	13	15
(Increase) decrease in accounts receivable	(280)	29
(Increase) decrease in utility billed receivable	(769)	(218)
(Increase) decrease in utility unbilled receivable	(2,805)	(577)
(Increase) decrease in intergovernmental receivable	655	(75)
(Increase) decrease in Water Conservation Programs receivable	5	109
(Increase) decrease in prepaid items	2	(6)
Increase (decrease) in accounts payable	(2,314)	3,739
Increase (decrease) in accrued payroll	151	96
Increase (decrease) in retainage payable	(872)	391
Increase (decrease) in compensated absences	433	192
Increase (decrease) in unearned revenue	3	3
Increase (decrease) in Water Conservation Programs payable	24	(82)
Increase (decrease) in deposits payable	(754)	819
Changes in net pension liability (asset) and related deferred inflows (outflows) of resources	3,108	2,482
Changes in OPEB liability and related deferred outflows and inflows of resources	203	173
Total adjustments	**14,903**	**23,843**
Net cash provided (used) by operating activities	**$ 34,050**	**$ 34,408**
SCHEDULE OF NON-CASH INVESTING, CAPITAL AND FINANCING ACTIVITIES:		
Capital contributions - capital assets	-	4,041
(Increase) decrease in arbitrage rebate liability	(664)	(673)
Increase (decrease) in fair value of investments	104	-
Lease and subscription additions	8	21

See accompanying notes to the financial statements

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The Water Utility exists under, and by virtue of, the City of Riverside (the City) Charter enacted in 1883. The Water Utility is responsible for the production, transmission and distribution of water for sale in the City, except for certain areas served by another water utility. The accompanying financial statements present only the financial position and the results of operations of the Water Utility, which is an enterprise fund of the City, and are not intended to present fairly the financial position and results of operations of the City in conformity with generally accepted accounting principles. However, certain disclosures are for the City as a whole, since such information is generally not available for the Water Utility on a separate fund basis. All amounts, unless otherwise indicated, are expressed in thousands of dollars.

BASIS OF ACCOUNTING

The Water Utility uses the accrual basis of accounting as required for enterprise funds with accounting principles generally accepted in the United States of America as applicable to governments. The accounting records of the Water Utility are also in conformity with the Uniform System of Accounts prescribed by the California Public Utilities Commission. The Water Utility is not subject to the regulations of the California Public Utilities Commission.

The Water Utility distinguishes operating revenues and expenses from non-operating items. Operating revenues and expenses generally result from providing services and producing and delivering goods in connection with an enterprise fund's principal ongoing operations. The principal operating revenues of the Water Utility are charges to customers for water sales and services. Operating expenses for the Water Utility include the cost of water sales and services, administrative expenses, and depreciation on capital assets. All revenues and expenses not meeting this definition are reported as non-operating revenues and expenses.

IMPLEMENTATION OF NEW ACCOUNTING PRONOUNCEMENTS

The following Governmental Accounting Standards Board (GASB) pronouncements became effective and were implemented during fiscal year 2024-2025:

GASB Statement No. 101, *Compensated Absences* - This Statement requires that liabilities for compensated absences be recognized for (1) leave that has not been used and (2) leave that has been used but not yet paid in cash or settled through noncash means. It also requires that a liability for certain types of compensated absences—including parental leave, military leave, and jury duty leave—not be recognized until the leave commences. This Statement also requires that a liability for specific types of compensated absences not be recognized until the leave is used. Further, this Statement establishes guidance for measuring a liability for leave that has not been used, generally using an employee's pay rate as of the date of the financial statements.

GASB Statement No. 102, *Certain Risk Disclosures* - This Statement requires a government to assess whether a concentration or constraint makes the primary government reporting unit or other reporting units that report a liability for revenue debt vulnerable to the risk of a substantial impact. Additionally, this Statement requires a government to assess whether an event or events associated with a concentration or constraint that could cause the substantial impact have occurred, have begun to occur, or are more likely than not to begin to occur within 12 months of the date the financial statements are issued. If a government determines that those criteria for disclosure have been met for a concentration or constraint, it should disclose information in notes to financial statements in sufficient detail to enable users of financial statements to understand the nature of the circumstances disclosed and the government's vulnerability to the risk of a substantial impact.

The following GASB pronouncements became effective and were implemented during fiscal year 2023-2024:

GASB Statement No. 99, *Omnibus 2022* - This Statement provides clarification on previously issued Statements, including the classification and reporting of derivative instruments within the scope of Statement No. 53, *Accounting and Financial Reporting for Derivative Instruments*, that do not meet the definition of either an investment derivative instrument or a hedging derivative instrument; clarification of provisions in Statement No. 87, *Leases*, as amended, related to the determination of the lease term, classification of a lease as a short-term lease, recognition and measurement of a lease liability and a lease asset, and identification of lease incentives; clarification of provisions in Statement No. 94, *Public-Private and Public-Public Partnerships and Availability Payment Arrangements*, related to (a) the determination of the public-private and public-public partnership (PPP) term and (b) recognition and measurement of installment payments and the transfer of the underlying PPP asset; clarification of provisions in Statement No. 96, *Subscription-Based Information Technology Arrangements*, related to the subscription-based information technology arrangement (SBITA) term,

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

IMPLEMENTATION OF NEW ACCOUNTING PRONOUNCEMENTS (CONTINUED)

classification of a SBITA as a short-term SBITA, and recognition and measurement of a subscription liability; extension of the period during which the London Interback Offered Rate (LIBOR) is considered an appropriate benchmark interest rate for the qualitative evaluation of the effectiveness of an interest rate swap that hedges the interest rate risk of taxable debt; accounting for the distribution of benefits as part of the Supplemental Nutrition Assistance Program (SNAP); disclosures related to nonmonetary transactions; pledges of future revenues when resources are not received by the pledging government; clarification of provisions in Statement No. 34, *Basic Financial Statements—and Management's Discussion and Analysis—for State and Local Governments*, as amended, related to the focus of the government-wide financial statements; terminology updates related to certain provisions of Statement No. 63, *Financial Reporting of Deferred Outflows of Resources, Deferred Inflows of Resources, and Net Position*; and terminology used in Statement 53 to refer to resource flows statements.

GASB Statement No. 100, *Accounting Changes and Error Corrections* - This Statement defines accounting changes as changes in accounting principles, changes in accounting estimates, and changes to or within the financial reporting entity and describes the transactions or other events that constitute those changes. It prescribes the accounting and financial reporting for (1) each type of accounting change and (2) error corrections, and requires that (a) changes in accounting principles and error corrections be reported retroactively by restating prior periods, (b) changes to or within the financial reporting entity be reported by adjusting beginning balances of the current period, and (c) changes in accounting estimates be reported prospectively by recognizing the change in the current period. Refer to Note 12 for current-year adjustments related to GASB Statement No. 100.

USE OF ESTIMATES

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the reported amounts of revenues and expenses during a reporting period. Accordingly, actual results could differ from those estimates.

REVENUE RECOGNITION

The Water Utility customers are billed monthly. Unbilled water service charges, including the Water Conservation Programs, are recorded at year-end and are included in accounts receivable. Unbilled accounts receivable totaled $6,788 and $3,983 at June 30, 2025 and 2024, respectively.

An allowance for doubtful accounts is maintained for utility and miscellaneous accounts receivable. The balance in this account is adjusted at fiscal year-end to approximate the amount anticipated to be uncollectible.

WATER UTILITY PLANT AND DEPRECIATION

The Water Utility defines capital assets as assets with an initial, individual cost of more than ten thousand dollars and an estimated useful life in excess of one year. This capitalization threshold was increased from the prior five-thoursand-dollar threshold effective May 2025. Water Utility plant assets are valued at historical costs or estimated historical cost, if actual historical cost is not available. Costs include labor; materials; allocated indirect charges such as engineering, supervision, construction and transportation equipment; retirement plan contributions and other fringe benefits. Contributed plant assets are valued at estimated fair value on the date contributed. The cost of relatively minor replacements is included in maintenance expense. Intangible assets that cost more than one hundred thousand dollars with useful lives of at least three years are capitalized and are recorded at cost.

Depreciation is recorded over the estimated useful lives of the related assets using the straight-line method. The estimated useful lives are as follows:

Supply, pumping and treatment plant	20-50 years
Transmission and distribution plant	25-50 years
General plant and equipment	5-50 years
Intangibles	5-15 years

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

RESTRICTED ASSETS

Proceeds of revenue bonds yet to be used for capital projects, as well as certain resources set aside for debt service, are classified as restricted assets on the Statements of Net Position because their use is limited by applicable bond covenants. Proceeds from financed purchase agreements yet to be used for the acquisition of capital equipment are also classified as restricted assets because their use is legally restricted for a specific purpose. Generally, the Water Utility will first apply restricted resources when expenses incurred for which both restricted and unrestricted resources are available.

In June 2004, the Water Utility began collecting a surcharge for Water Conservation Programs. The surcharge is a 1.5% charge applied to all water customer bills. It has been in place for 20 years and helps fund water conservation programs and customer education. The surcharge can only be used for conservation, education, and water-use efficiency rebate programs; and research, development, and demonstration programs to advance science and technology with respect to water conservation. On January 22, 2024, the Board conducted a public hearing to receive input on the renewal of the Water Conservation Charge. At the meeting, the last surcharge was adopted on April 22, 2014 and was set to expire on April 22, 2024. Continued from March 19, 2024, on April 16, 2024, City Council voted to discontinue the Water Conservation Surcharge. The Water Conservation Program will continue until funds are exhausted. The Water Conservation Surcharge expired on April 22, 2024, and has been removed from customer bills.

CASH AND CASH EQUIVALENTS

For the Statements of Cash Flows, cash and cash equivalents include all unrestricted and restricted highly liquid investments with original purchase maturities of three months or less, and all bond construction proceeds available for capital projects held at fiscal agent. Pooled cash and investments in the City’s Treasury represent monies in a cash management pool. Such accounts are similar in nature to demand deposits and are classified as cash equivalents for the purpose of presentation in the Statements of Cash Flows. Further details regarding cash and cash equivalents can be found in Note 2.

CASH AND INVESTMENTS

In accordance with the Water Utility policy, the Water Utility’s cash and investments, except for cash and investments with fiscal agents, are invested in a pool managed by the Treasurer of the City. Cash accounts of all funds are pooled for investment purposes to enhance safety and liquidity, while maximizing interest earnings. The Water Utility does not own specific, identifiable investments of the pool. The pooled interest earned is allocated monthly based on the month end cash balances.

The Water Utility values its cash and investments in accordance with provisions of GASB Statement No. 72, *Fair Value Measurement and Application*, which requires governmental entities to use valuation techniques that are appropriate under the circumstances and for which sufficient data are available to measure fair value. The techniques should be consistent with one or more of the following approaches: the market approach, the cost approach or the income approach. Valuation includes a hierarchy of inputs with three distinct levels. Level 1 are quoted prices in an active market for identical assets; Level 2 inputs are significant other observable inputs; and Level 3 inputs are significant unobservable inputs. The Water Utility does not value any of its investments using level 3 inputs. Further details regarding cash and investments can be found in Note 2.

City-wide information concerning cash and investments as of June 30, 2025, including authorized investments, fair value measurement and application, custodial credit risk, credit and interest rate risk for debt securities and concentration of investments, carrying amount and market value of deposits and investments can be found in the notes to the City’s financial statements in the City’s Annual Comprehensive Financial Report.

CASH AND INVESTMENTS AT FISCAL AGENTS

Cash and investments maintained by fiscal agents are considered restricted by the Water Utility. Pursuant to certain bond indentures, the fiscal agent establishes, maintains and holds in trust a separate restricted rebatable arbitrage account. The Water Utility calculates the rebatable arbitrage liability annually and fiscal agent pays the computed arbitrage rebate to the U.S. Treasury every five years. Further details regarding arbitrage can be found in Note 8. Further details regarding cash and investments at fiscal agents can be found in Note 2.

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

CASH AND INVESTMENTS AT FISCAL AGENTS (CONTINUED)

CalPERS's positive investment returns contributed to the reduction of the unfunded accrued liability (UAL); as a result, originally budgeted UAL payments were redirected to the Water Utility's restricted cash and investments held at fiscal agent to aid the Water Utility in long-term management of rising pension costs. See Notes 6 for further discussion related to the CalPERS pension plan, including UAL.

DESIGNATED CASH RESERVES

The Riverside Public Utilities Cash Reserve Policy establishes several designated cash reserves in the Water Utility for strategic purposes. Designated reserves are set aside for specific purposes determined by the Board of Public Utilities and City Council. Designated reserves may be held for capital or operating purposes.

Designated cash reserve balances as of June 30, 2025 and 2024 were as follows: Property Reserve $6,325 and $6,135, Recycled Water Reserve $916 and $778, Customer Deposits $959 and $858, and Capital Repair and Replacement Reserve $2,510 and $2,437, respectively. The combined total for these reserves was $10,710 and $10,208 at June 30, 2025 and 2024, respectively, and is included as a component of unrestricted cash and cash equivalents in the accompanying Statements of Net Position.

DERIVATIVES

The Water Utility accounts for derivative instruments using GASB Statement No. 53, *Accounting and Financial Reporting for Derivative Instruments* (GASB 53). This Statement requires the Water Utility to report its derivative instruments at fair value. Changes in fair value for effective hedges are to be reported as deferred inflows and outflows of resources on the Statements of Net Position. Changes in fair value of derivative instruments not meeting the criteria for an effective hedge, or that are associated with investments are to be reported in the non-operating revenues section of the Statements of Revenue, Expenses and Changes in Net Position.

The Water Utility has determined that its interest rate swaps associated with variable-rate obligations are derivative instruments under GASB 53. See Note 4 for further discussion related to the Water Utility's interest rate swaps.

BOND PREMIUMS/DISCOUNTS AND GAINS/LOSSES ON REFUNDING

Bond premium/discounts and gains/losses on refunding (including gains/losses related to interest rate swap transactions) are deferred and amortized over the term of the new bonds using the effective interest method. Bonds payable are reported net of the applicable bond premium or discount. Gains/losses on refunding are reported as deferred inflows or outflows of resources.

CUSTOMER DEPOSITS

The City holds customer deposits as security for the payment of utility bills and plan check fee deposits for future water connection. The Water Utility's portion of these deposits as of June 30, 2025 and 2024 was $1,099 and $1,853, respectively.

COMPENSATED ABSENCES

The accompanying financial statements include accruals for salaries, fringe benefits and compensated absences due to employees at June 30, 2025 and 2024. The Water Utility treats compensated absences due to employees as an expense and a liability of which a current portion is included in accounts payable and other accruals in the accompanying Statements of Net Position. The amount accrued for compensated absences was $3,110 and $2,677 at June 30, 2025 and 2024, respectively.

Employees receive 10 to 25 vacation days per year based upon length of service. A maximum of two years' vacation accrual may be accumulated, and unused vacation is paid in cash upon separation.

Employees generally receive one day of sick leave for each month of employment with unlimited accumulation. Upon retirement or death, certain employees or their estates receive a percentage of unused sick leave paid in a lump sum based on longevity.

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

COMPENSATED ABSENCES (CONTINUED)

During fiscal year 2024-2025, GASB Statement No. 101, *Compensated Absences* became effective and was implemented. This Statement addresses accounting and financial reporting for certain liabilities for compensated absences. See Note 5 for further information regarding compensated absences.

INSURANCE PROGRAMS

The Water Utility participates in a self-insurance program for workers' compensation and general liability coverage that is administered by the City. The Water Utility pays an amount to the City based on actuarial estimates of the amounts needed to fund prior and current year claims and incidents that have been incurred but not reported. The City maintains property insurance on most City property holdings with a shared limit of $1 billion.

City-wide information concerning risks, insurance policy limits and deductibles and designation of general fund balance for risks for the year ended June 30, 2025, may be found in the notes to the City's financial statements in the City's Annual Comprehensive Financial Report.

Although the ultimate amount of losses incurred through June 30, 2025 is dependent upon future developments, management believes that amounts paid to the City are sufficient to cover such losses. Premiums paid to the City by the Water Utility were $821 and $943 for the years ended June 30, 2025 and 2024, respectively. Any losses above the City's reserves would be covered through increased rates charged to the Water Utility in future years.

EMPLOYEE RETIREMENT PLAN

The City contributes to the California Public Employees Retirement System (CalPERS), an agent multiple employer public employee defined benefit pension plan. CalPERS provides retirement and disability benefits, annual cost-of-living adjustments, and death benefits to plan members and beneficiaries. CalPERS acts as a common investment and administrative agent for participating public entities within the State of California. Benefit provisions and all other requirements are established by state statute and City ordinance.

For purposes of measuring the net pension asset/liability and deferred outflows/inflows of resources related to pensions, and pension expense, information about the fiduciary net position of the City of Riverside California Public Employees' Retirement System plans (Plans) and additions to/deductions from the Plans' fiduciary net position have been determined on the same basis as they are reported by CalPERS. For this purpose, benefit payments (including refunds of employee contributions) are recognized when due and payable in accordance with the benefit terms. Investments are reported at fair value. Further details of employee retirement plan can be found in Note 6.

OTHER POSTEMPLOYMENT BENEFITS (OPEB)

OPEB refers to the benefits, other than pensions, that the City provides as part of an employee's retirement benefits. The net OPEB obligation is defined as the liability of employers contributing to employees for benefits provided through a defined benefit OPEB plan that is administered through a trust. Further details for OPEB can be found in Note 7.

DEFERRED OUTFLOWS AND DEFERRED INFLOWS OF RESOURCES

When applicable, the Statements of Net Position will report a separate section for deferred outflows of resources. Deferred outflows of resources represent outflows of resources (consumption of net position) that apply to future periods and that, therefore, will not be recognized as an expense or expenditure until that time. Deferred outflows of resources consist of losses on refunding and deferred outflows related to pension and OPEB, which include pension contributions subsequent to the measurement date, difference between actual and actuarial determined contribution, changes in assumptions and net differences between projected and actual earnings on pension plan investments.

Conversely, deferred inflows of resources represent inflows of resources (acquisition of net position) that apply to future periods and that, therefore, are not recognized as an inflow of resources (revenue) until that time. Deferred inflows of resources consist of changes in derivative values, lease-related items and deferred inflows related to pension and OPEB, which include changes in assumptions, differences between expected and actual experience and net differences between projected and actual earnings on pension plan investments.

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

REGULATORY ASSETS AND DEFERRED REGULATORY CHARGES

In accordance with regulatory accounting criteria set forth in GASB Codification (GASB Statement No. 62), enterprise funds that are used to account for rate-regulated activities are permitted to defer certain expenses and revenues that would otherwise be recognized when incurred, provided that the Water Utility is recovering or expects to recover or refund such amounts in rates charged to its customers. Accordingly, regulatory assets and/or deferred regulatory charges related to debt issuance costs have been recognized in the Statements of Net Position.

NET POSITION

The Water Utility's net position represents the difference between assets and deferred outflows of resources less liabilities and deferred inflows of resources, which is classified into the following three components:

Net investment in capital assets – this component consists of capital assets (net of accumulated depreciation) reduced by the outstanding balance of any bonds or other borrowings that are attributable to the acquisition, construction, or improvement of those assets, excluding unspent bond proceeds.

Restricted – this component represents restricted assets less liabilities and deferred inflows related to those assets. Restricted assets are recorded when there are limitations imposed by creditors (such as through debt covenants), contributors, or laws or regulation of other governments or constraints imposed by law through constitutional provisions or through enabling legislation.

Unrestricted – this component consists of net position that does not meet the definition of "restricted" or "net investment in capital assets."

CONTRIBUTIONS TO THE CITY'S GENERAL FUND

Pursuant to the City of Riverside Charter and the voter approval of Measure A on June 4, 2013, the Water Utility may transfer up to 11.5 percent of prior year's gross operating revenues, including adjustments, to the City's general fund. In fiscal years ended June 30, 2025 and 2024, $8,230 and $8,108, respectively, was transferred, representing 11.5 percent. Additional information can be found in Note 10.

BUDGETS AND BUDGETARY ACCOUNTING

The Water Utility presents, and the City Council adopts, a biennial budget. The proposed budget includes estimated expenses and forecasted revenues. The City Council generally adopts the Water Utility's budget in June biennially via resolution.

LEASES AND SUBSCRIPTION-BASED INFORMATION TECHNOLOGY ARRANGEMENTS

Leases are defined by the general government as the right to use an underlying asset. As lessee, the Water Utility recognizes a lease liability and a lease asset at the beginning of a lease period unless the lease is considered a short-term lease or transfers ownership of the underlying asset. Lease assets are measured based on the net present value of the future lease payments at inception, using the weighted average cost of capital, which approximate the incremental borrowing rate. Re-measurement of a lease liability occurs when there is a change in the lease term and/or other changes that are likely to have a significant impact on the lease liability. The Water Utility calculates the amortization of the discount on the lease liability and report that amount as outflows of resources. Payments are allocated first to accrued interest liability and then to the lease liability. Variable lease payments based on the usage of the underlying assets are not included in the lease liability calculations but are recognized as outflows of resources in the period in which the obligation was incurred. As lessor, the Water Utility recognizes a lease receivable. The lease receivable is measured using the net present value of future lease payments to be received for the lease term and deferred inflow of receivables at the beginning of the lease term. Periodic amortization of the discount on the receivable are reported as interest revenue for that period. Deferred inflows of resources are recognized as inflows on a straight-line basis over the term of the lease. This recognition does not apply to short-term leases, contracts that transfer ownership, leases of assets that are investments, or certain regulated leases. Any initial direct costs are reported as an outflow of resources for that period.

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

LEASES AND SUBSCRIPTION-BASED INFORMATION TECHNOLOGY ARRANGEMENTS (CONTINUED)

Re-measurement of lease receivables occur when there are modifications, including but not limited to changes in the contract price, lease term, and adding or removing an underlying asset to the lease agreements.In the case of a partial or full lease termination, the carrying value of the lease receivable and the related deferred inflow of resources will be reduced and will include a gain or loss for the difference. For lease contracts that are short-term, the Water Utility recognizes short-term lease payments as inflows of resources (revenues) based on the payment provisions of the lease contract. Liabilities are only recognized if payments are received in advance, and receivables are only recognized if payments are received subsequent to the reporting period. Additional disclosures regarding regulated leases are in Note 11.

Subscription-Based Information Technology Arrangements (SBITAs) are contracts that convey control of the right to use another party's IT software, alone or in combination with tangible capital assets, as specified in the contract for a period of time in an exchange or exchange-like transaction. To determine whether a contract conveys control of the right to use the underlying IT assets, the Water Utility assesses both the right to obtain the present service capacity from use of the underlying IT assets and the right to determine the nature and manner of use of the underlying IT assets as specified in the contract. Contracts that solely provide IT support services are excluded from the definition of a SBITA. The subscription term is the period during which the Water Utility has a noncancellable right to use the underlying IT assets, plus the periods covered by the Water Utility's option to extend the SBITA if it is reasonably certain, based on all relevant factors, that the government will exercise that option. Periods for which both the government and the SBITA vendor have an option to terminate the SBITA without permission from the other party (or if both parties have to agree to extend) are cancelable periods and are excluded from the subscription term. Additional disclosures regarding SBITAs are in Note 11.

RECLASSIFICATIONS/RESTATEMENTS

During fiscal year 2025, certain restatements were made to correct errors identified in prior-year financial statements. All error corrections were recorded as adjustments to the beginning net position of fiscal year 2024, and the related restatements are reflected in the change in net position for that year. Additional information is provided in Note 12.

NOTE 2. CASH AND INVESTMENTS

Cash and investments at June 30, 2025 and 2024, consist of the following (in thousands):

	June 30, 2025	June 30, 2024
	Fair Value	
Equity interest in City Treasurer's investment pool	$ 74,127	$ 66,442
Cash and investments at fiscal agent	2,835	1,840
Cash and cash equivalents at fiscal agent	25,483	34,555
Total cash, cash equivalents and investments	$ 102,445	$ 102,837

The amounts above are reflected in the accompanying financial statements as:

	June 30, 2025	June 30, 2024
Unrestricted cash and cash equivalents	$ 60,558	$ 53,449
Restricted cash and cash equivalents	13,569	12,993
Restricted cash and investments at fiscal agent	2,835	1,840
Restricted cash and cash equivalents at fiscal agent	25,483	34,555
Total cash, cash equivalents and investments	$ 102,445	$ 102,837

The investment types in the tables below related to the Water Utility’s investments in the City Treasurer’s investment pool represent the Water Utility’s prorated share of the investment types in the investment pool and do not represent ownership interests in the individual investments.

NOTE 2. CASH AND INVESTMENTS (CONTINUED)

The Water Utility categorizes its fair value measurements within the fair value hierarchy established by generally accepted accounting principles. The Water Utility has the following recurring fair value measurements as of June 30, 2025 and 2024:

Investment Type	June 30, 2025 Fair Value	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Investments not Subject to Fair Value Hierarchy
Held by fiscal agent					
Money market funds	$ 28,317	$ -	$ -	$ -	$ 28,317
City Treasurer's investment pool[1]					
Money market funds	359	-	-	-	359
Joint powers authority pools	9,243	-	-	-	9,243
Mortgage pass-through securities	2,840	-	2,840	-	-
Asset-backed securities	8,660	-	8,660	-	-
US Treasury obligations	29,994	-	29,994	-	-
Federal agency obligations	2,554	-	2,554	-	-
Medium-term corporate notes	15,094	-	15,094	-	-
Supranational securities	5,384	-	5,384	-	-
Total	$ 102,445	$ -	$ 64,526	$ -	$ 37,919

Investment Type	June 30, 2024 Fair Value	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Investments not Subject to Fair Value Hierarchy
Held by fiscal agent					
Money market funds	$ 36,395	$ -	$ -	$ -	$ 36,395
City Treasurer's investment pool[1]					
Money market funds	63	-	-	-	63
Joint powers authority pools	13,542	-	-	-	13,542
Mortgage pass-through securities	1,993	-	1,993	-	-
Asset backed securities	5,768	-	5,768	-	-
US Treasury obligations	21,643	-	21,643	-	-
Federal agency obligations	6,143	-	6,143	-	-
Medium-term corporate notes	13,268	-	13,268	-	-
Supranational securities	4,022	-	4,022	-	-
Total	$ 102,837	$ -	$ 52,837	$ -	$ 50,000

[1]Additional information on investment types, fair value measurement, interest rate risk and credit risk may be found in the notes to the City's financial statements in the City's Annual Comprehensive Financial Report.

NOTE 2. CASH AND INVESTMENTS (CONTINUED)

Cash and investments distribution by maturities as of June 30, 2025 and 2024, are as follows:

Investment Type	June 30, 2025 Fair Value	Remaining Maturity (in Months) 12 Months or Less	13 to 36 Months	37 to 60 Months
Held by fiscal agent				
Money market funds	$ 28,317	$ 28,317	$ -	$ -
City Treasurer's investment pool[1]				
Money market funds	359	359	-	-
Joint powers authority pools	9,243	9,243	-	-
Mortgage pass-through securities	2,840	16	1,303	1,521
Asset-backed securities	8,660	305	2,716	5,639
US Treasury obligations	29,994	-	11,096	18,898
Federal agency obligations	2,554	569	1,985	-
Medium-term corporate notes	15,094	2,218	6,339	6,537
Supranational securities	5,384	1,038	-	4,346
Total	$ 102,445	$ 42,065	$ 23,439	$ 36,941

Investment Type	June 30, 2024 Fair Value	Remaining Maturity (in Months) 12 Months or Less	13 to 36 Months	37 to 60 Months
Held by fiscal agent				
Money market funds	$ 36,395	$ 36,395	$ -	$ -
City Treasurer's investment pool[1]				
Money market funds	63	63	-	-
Joint powers authority pools	13,542	13,542	-	-
Mortgage pass-through securities	1,993	608	286	1,099
Asset-backed securities	5,768	324	1,970	3,474
US Treasury obligations	21,643	-	6,791	14,852
Federal agency securities	6,143	1,891	2,567	1,685
Medium-term corporate notes	13,268	2,025	5,846	5,397
Supranational securities	4,022	263	1,460	2,299
Total	$ 102,837	$ 55,111	$ 18,920	$ 28,806

[1]Additional information on investment types, fair value measurement, interest rate risk and credit risk may be found in the notes to the City’s financial statements in the City’s Annual Comprehensive Financial Report.

NOTE 2. CASH AND INVESTMENTS (CONTINUED)

Presented below is the actual rating as of June 30, 2025 and 2024 for each investment type:

Investment Type	June 30, 2025 Fair Value	Rating as of Year End AAA	AA	A	Unrated
Held by Fiscal Agent					
Money Market Funds	$ 28,317	$ 26,866	$ -	$ -	$ 1,451
City Treasurer's investment pool[1]					
Money market funds	359	359	-	-	-
Joint powers authority pools	9,243	9,243	-	-	-
Mortgage pass-through securities	2,840	2,258	582	-	-
Asset-backed securities	8,660	6,181	-	-	2,479
US Treasury obligations	29,994	-	29,994	-	-
Federal agency obligations	2,554	-	2,554	-	-
Medium-term corporate notes	15,094	468	4,348	7,064	3,214
Supranational securities	5,384	-	-	-	5,384
Total	$ 102,445	$ 45,375	$ 37,478	$ 7,064	$ 12,528

Investment Type	June 30, 2024 Fair Value	Rating as of Year End AAA	AA	A	Unrated
Held by fiscal agent					
Money market funds	$ 36,395	$ 35,238	$ -	$ -	$ 1,157
City Treasurer's investment pool[1]					
Money market funds	63	63	-	-	-
Joint powers authority pools	13,542	13,542	-	-	-
Mortgage pass-through securities	1,993	1,808	185	-	-
Asset backed securities	5,768	4,422	-	-	1,346
US Treasury obligations	21,643	-	21,643	-	-
Federal agency obligations	6,143	-	6,143	-	-
Medium-term corporate notes	13,268	402	4,087	6,511	2,268
Supranational securities	4,022	-	-	-	4,022
Total	$ 102,837	$ 55,475	$ 32,058	$ 6,511	$ 8,793

[1]Additional information on investment types, fair value measurement, interest rate risk and credit risk may be found in the notes to the City's financial statements in the City's Annual Comprehensive Financial Report.

NOTE 3. CAPITAL ASSETS

The following is a summary of changes in utility plant and lease and subscription assets during the fiscal years ended June 30, 2025 and 2024 (in thousands):

	Balance As of 6/30/2023*	Restatement**	Additions	Retirements/ Transfers	Balance As of 6/30/2024*	Additions	Retirements/ Transfers	Balance As of 6/30/2025
Source of supply	$ 81,932	$ -	$ 3,182	$ -	$ 85,114	$ 2,433	$ -	$ 87,547
Pumping	39,969	-	3,629	-	43,598	512	-	44,110
Treatment	45,860	-	29	-	45,889	31	(507)	45,413
Transmission and distribution	552,118	-	14,539	(1,305)	565,352	27,395	(4,500)	588,247
General	18,725	-	814	(236)	19,303	4,506	(913)	22,896
Intangible	4,181	-	-	-	4,181	119	-	4,300
Depreciable utility plant	742,785	-	22,193	(1,541)	763,437	34,996	(5,920)	792,513
Less accumulated depreciation:								
Source of supply	(27,709)	(41)	(2,058)	-	(29,808)	(2,236)	-	(32,044)
Pumping	(16,524)	(32)	(815)	-	(17,371)	(1,289)	-	(18,660)
Treatment	(20,208)	(4)	(1,319)	-	(21,531)	(1,279)	-	(22,810)
Transmission and distribution	(216,399)	(886)	(11,889)	891	(228,283)	(12,407)	4,500	(236,190)
General	(14,089)	(15)	(643)	236	(14,511)	(878)	913	(14,476)
Intangible	(4,143)	(80)	(30)	-	(4,253)	(11)	-	(4,264)
Accumulated depreciation	(299,072)	(1,058)	(16,754)	1,127	(315,757)	(18,100)	5,413	(328,444)
Net depreciable utility plant	443,713	(1,058)	5,439	(414)	447,680	16,896	(507)	464,069
Land	20,841	-	46	(17)	20,870	-	-	20,870
Intangible, non-amortizable	10,845	-	-	-	10,845	-	-	10,845
Construction in progress	42,055	(10,781)	30,152	(18,197)	43,229	9,068	(23,709)	28,588
Nondepreciable utility plant	73,741	(10,781)	30,198	(18,214)	74,944	9,068	(23,709)	60,303
Total utility plant, net	$ 517,454	$ (11,839)	$ 35,637	$ (18,628)	$ 522,624	$ 25,964	$ (24,216)	$ 524,372
Lease and subscription assets, being amortized:								
Machinery and equipment-Intangible	21	-	21	(16)	26	8	(5)	29
Subscription-based information technology arrangements	32	-	1	-	33	-	(33)	-
Total lease and subscription assets	53	-	22	(16)	59	8	(38)	29
Less lease accumulated amortization:								
Machinery and equipment-Intangible	(10)	-	(5)	9	(6)	(5)	5	(6)
Subscription-based information technology arrangements	(15)	-	(10)	-	(25)	(8)	33	-
Total lease accumulated amortization	(25)	-	(15)	9	(31)	(13)	38	(6)
Total lease and subscription assets, net	28	-	7	(7)	28	(5)	-	23
Total capital assets being depreciated, net	$ 517,482	$ (11,839)	$ 35,644	$ (18,635)	$ 522,652	$ 25,959	$ (24,216)	$ 524,395

* *As restated* .

** *Restatement reflects adjustments to beginning net position for prior-period capital asset corrections identified during FY 2024–25. These adjustments include capitalization of assets previously placed into service with the related accumulated depreciation, and the reclassification of certain long-standing Construction in Progress balances that did not meet capitalization criteria. These corrections were recorded to properly state beginning net position. For further detail refer to Note-12 Restatement of Beginning Net Position.*

NOTE 4. LONG-TERM OBLIGATIONS

The following is a summary of changes in long-term obligations during the fiscal years ended June 30, 2025 and 2024 (in thousands):

	Balance As of 6/30/2023	Additions	Reductions	Balance As of 6/30/2024	Additions	Reductions	Balance As of 6/30/2025	Due Within One Year
Revenue bonds	$ 265,294	$ -	$ (9,129)	$ 256,165	$ -	$ (9,645)	$ 246,520	$ 8,840
Arbitrage liability	-	673	-	673	664	-	1,337	-
Pension obligation bonds	19,924	-	(1,640)	18,284	-	(1,815)	16,469	1,867
Direct borrowings:								
Financed purchases	985	-	(237)	748	4,814	(543)	5,019	868
Contracts payable - water stock acquisition rights	933	-	(2)	931	-	-	931	150
Total long-term obligations	$ 287,136	$ 673	$ (11,008)	$ 276,801	$ 5,478	$ (12,003)	$ 270,276	$ 11,725

Long-term debt consists of the following (in thousands):

CONTRACTS PAYABLE

	June 30, 2025	June 30, 2024
Water Stock Acquisitions: Payable to various water companies	$ 931	$ 931
Total contracts payable	931	931

PENSION OBLIGATION BONDS PAYABLE

	June 30, 2025	June 30, 2024
$31,960 2017 Taxable Pension Obligation Bonds Series A: fixed rate bonds issued by the City due in annual installments from $2,910 to $3,580 through June 2027, with coupons from 1.3 to 3.1 percent. The Water Utility's proportional share of the outstanding debt is 10.7 percent.	$ 754	$ 1,114
$201,080 2020 Taxable Pension Obligation Bonds Series A (Miscellaneous): fixed rate bonds issued by the City due in annual installments from $1,285 to $14,625 through June 2045, with coupons from 1.7 to 3.9 percent. The Water Utility's proportional share of the outstanding debt is 10.2 percent.	15,715	17,170
Total pension obligation bonds payable	16,469	18,284

REVENUE BONDS PAYABLE

	June 30, 2025	June 30, 2024
$67,790 2009 Water Revenue Series B Bonds: fixed rate, federally taxable, Build America Bonds due in annual principal installments from $2,475 to $4,985 from October 1, 2021 through October 1, 2039, interest from 5.1 to 6.4 percent, excluding 33% sequestration credit from the IRS, effective October 1, 2020.	$ 57,365	$ 60,115
$59,000 2011 Water Revenue/Refunding Series A Bonds: variable rate bonds due in annual principal installments from $600 to $3,950 through October 1, 2035. Interest rate is subject to daily repricing (net interest rate, including swaps, at June 30, 2019 was 3.1 percent). Partially refunded $26,900 on April 1, 2019 with 2019A Water Refunding Bonds.	24,050	24,050
$114,215 2019 Water Revenue Refunding Series A Bonds: fixed rate bonds due in annual principal installments from $1,680 to $8,455 through October 1, 2048, interest of 5.0 percent.	89,105	93,895
$58,025 2022 Water Revenue Series A Bonds: fixed rate bonds due in annual principal installments from $735 to $3,605 through October 1, 2052, interest of 5.0 percent.	56,370	57,290
Total water revenue bonds payable	226,890	235,350
Total water revenue bonds, pension obligation bonds and contracts payable	244,290	254,565
Unamortized bond premium	19,630	20,815
Total water revenue bonds, pension obligation bonds and contracts payable, including bond premium	263,920	275,380
Less current portion	(10,857)	(10,425)
Total long-term water revenue bonds, pension obligation bonds and contracts payable	$ 253,063	$ 264,955

NOTE 4. LONG-TERM OBLIGATIONS (CONTINUED)

Pension Obligation Bonds - The Water Utility is obligated to pay its share of the City's pension obligation bonds (POB), which the City issued in 2005 and refinanced a portion in May 2017. The bond proceeds were deposited with CalPERS to fund the unfunded actuarial accrued liability for non-safety employees.

In fiscal year ended June 30, 2020, the City issued $432,165 2020 Taxable Pension Obligation Bonds Series A. The bonds were issued to reduce the City's unfunded pension liability in both the City's Miscellaneous and Safety CalPERS plans. It is estimated the issuance will save the City's General Fund approximately $178.5 million throughout the life of the bonds. The fixed rate bonds issued by the City under the miscellaneous plan are due in annual installments from $1,285 to $14,625 through June 2043, with coupons from 1.7% to 3.9%. The Water Utility's proportional share of the miscellaneous plan is 10.2%.

The Water Utility's proportional share of the outstanding principal amount of both pension obligation bonds was $16,469 and $18,284 as of June 30, 2025 and 2024, respectively. For more discussion relating to the City's pension obligation bond issuance, see the notes to the City's financial statements in the City's Annual Comprehensive Financial Report for the fiscal year ended June 30, 2025.

Remaining pension obligation bond debt service payments will be made from revenues of the Water Fund.

As of June 30, 2025, the annual debt service requirements to maturity are as follows (in thousands):

Fiscal Year	Principal	Interest	Total
2026	$ 1,867	$ 562	$ 2,429
2027	1,793	514	2,307
2028	1,182	465	1,647
2029	941	432	1,373
2030	710	405	1,115
2031-2035	4,616	1,592	6,208
2036-2040	4,332	668	5,000
2041-2043	1,028	60	1,088
Total	$ 16,469	$ 4,698	$ 21,167

As of June 30, 2024, the annual debt service requirements to maturity were as follows (in thousands):

Fiscal Year	Principal	Interest	Total
2025	$ 1,815	$ 605	$ 2,420
2026	1,867	562	2,429
2027	1,793	514	2,307
2028	1,182	465	1,647
2029	941	432	1,373
2030-2034	4,323	1,752	6,075
2035-2039	4,631	847	5,478
2040-2043	1,732	126	1,858
Total	$ 18,284	$ 5,303	$ 23,587

Revenue Bonds - All water revenue bonds are covenanted per the Amended and Restated Resolution No. 17664 (Water) Master Resolution that upon the occurrence and continuation of an event of default, the owners of 25% in aggregate amount of Bond Obligation may, by written notice to the City, declare the entire unpaid principal and accreted value of the bonds due and payable should the City fail to pay its debts as they become due or upon the entry of any decree or order of bankruptcy of the City.

The Tax Reform Act of 1986 (the Act) requires the Water Utility to calculate and remit rebatable arbitrage earnings to the Internal Revenue Service. Certain debt and interest earnings on the proceeds of the Water Utility are subject to the requirements of the Act, which contain yield restrictions on investment of proceeds from tax-exempt financing in higher-yielding taxable securities. The balance in the arbitrage liability as of June 30, 2025 and 2024 was $1,337 and $673, respectively, and is included in long-term obligations, less current portion, in the accompanying Statements of Net Position.

NOTE 4. LONG-TERM OBLIGATIONS (CONTINUED)

$58,025 Water Revenue Bonds Series A. The bonds were issued in December 2022 to fund short-term and long-term capital projects. Interest on the bonds is 5%, payable in April and October of each year. Principal payments are due in annual installments through October 1, 2052, and range from $735 to $3,605.

Remaining revenue bond debt service payments will be made from revenues of the Water Fund.

As of June 30, 2025, the annual debt service requirements to maturity are as follows (in thousands):

Fiscal Year	Principal	Interest	Total
2026	$ 8,840	$ 10,257	$ 19,097
2027	9,245	9,831	19,076
2028	11,002	9,385	20,387
2029	10,095	8,920	19,015
2030	10,755	8,429	19,184
2031-2035	58,385	35,044	93,429
2036-2040	64,935	20,955	85,890
2041-2045	20,820	11,242	32,062
2046-2050	23,845	5,413	29,258
2051-2053	10,305	790	11,095
Premium	19,630	-	19,630
Total	$ 247,857	$ 120,266	$ 368,123

As of June 30, 2024 the annual debt service requirements to maturity are as follows (in thousands):

Fiscal Year	Principal	Interest	Total
2025	$ 8,460	$ 10,664	$ 19,124
2026	8,840	10,257	19,097
2027	9,245	9,831	19,076
2028	10,338	9,385	19,723
2029	10,095	8,920	19,015
2030-2034	56,485	37,481	93,966
2035-2039	69,015	24,003	93,018
2040-2044	24,815	12,364	37,179
2045-2049	25,315	6,642	31,957
2050-2053	13,415	1,383	14,798
Premium	20,815	-	20,815
Total	$ 256,838	$ 130,930	$ 387,768

Pledged Revenue - The Water Utility has a number of debt issuances (revenue bonds) outstanding that are collateralized by the pledging of water revenues. The amount and term of the remainder of these commitments are indicated in the revenue bonds payable and annual debt service requirements to maturity tables presented within this Note 4. The purpose of the debt issuances was for the financing of various Water Utility capital improvement projects.

For June 30, 2025 and 2024, debt service payments as a percentage of the pledged gross revenue, net of certain expenses where so required by the debt agreement, are indicated in the table below. The debt service coverage ratios also approximate the relationship of the debt service to pledged revenue for the remainder of the term of the commitment.

NOTE 4. LONG-TERM OBLIGATIONS (CONTINUED)

Fiscal Year Ended	Description of Pledged Revenues	Annual Amount of Pledged Revenue (net of expenses) [1, 2, 3, 4]	Annual Debt Service Payments	Debt Service Coverage Ratio[5]
June 30, 2025	Water revenues	$ 53,445	$ 21,294	2.51
June 30, 2024	Water revenues	$ 39,666	$ 20,914	1.90

[1]Excludes GASB 68 *Accounting and Financial Reporting for Pension* non-cash adjustments of $3,107 and $2,483 for June 30, 2025 and 2024, respectively.

[2]Excludes GASB 75 *Accounting and Financial Reporting for Postemployment Benefits Other Than Pensions* non-cash adjustments of $203 and $173 for June 30, 2025 and 2024, respectively.

[3]Includes GASB 87 *Leases* net revenue adjustment of $3,049 and $3,023 for June 30, 2025 and 2024, respectively.

[4]Includes rebatable arbitrage of $664 and $673 for June 30, 2025 and 2024, respectively.

[5] As restated for the fiscal year ended June 30, 2024.

LINE OF CREDIT

On February 1, 2019, the City entered into a subordinate line of credit agreement with U.S. Bank, National Association. The agreement was renewed on June 2, 2025. The Subordinate Line of Credit is a tool approved through the Electric and Water Utility Five-Year Rate Plan to manage rate increases by enabling the Water Utility to reduce cash levels while maintaining compliance with the Riverside Public Utilities Cash Reserve Policy. Under the terms and conditions of the agreement, the City may borrow up to $25,000 for purposes of the capital or operating financial needs of the Water System. There were no borrowings against the line as of June 30, 2025 and 2024.

LETTERS OF CREDIT

The Water Utility's Issue of the 2011A Water Revenue Bonds require an additional layer of security between the Water Utility and the purchaser of the bonds.

As of June 30, 2025 and 2024, the Water Utility had the following letter of credit (LOC) to provide liquidity should all or a portion of the debt be optionally tendered to the remarketer without being successfully remarketed:

Debt Issue	LOC Provider	LOC Expiration Date	Annual Commitment Fee
2011A Water Revenue Bonds	PNC Bank, NA	2025	0.230 %

Prior to the expiration of the current LOC agreement with PNC, the City will either renew or establish a new letter of credit agreement for the 2011A Water Revenue Bonds. To the extent that remarketing proceeds are insufficient or not available, tendered amounts will be paid from drawings made under an irrevocable direct-pay letter of credit.

INTEREST RATE SWAPS ON REVENUE BONDS

The Water Utility has one cash flow hedging derivative instrument, which is a pay-fixed swap. The swap was employed as a hedge against debt that was refunded in 2008 and 2011. At the time of the refunding, hedge accounting ceased to be applied. The balance of the deferral account for the swap is included as part of the deferred loss on refunding associated with the new bonds. The swap was also employed as a hedge against the new debt. Hedge accounting was applied to that portion of the hedging relationship, which was determined to be effective. The negative fair value of the interest rate swaps related to the new hedging relationship has been recorded and deferred on the Statements of Net Position.

A summary of the derivative activity for the year ended June 30, 2025 is as follows:

	Notional Amount	Fair Value as of June 30, 2025	Change in Fair Value for Fiscal Year
2011 Water Refunding/Revenue Bonds Series A	$ 24,050	$ (1,185)	$ (354)

NOTE 4. LONG-TERM OBLIGATIONS (CONTINUED)

INTEREST RATE SWAPS ON REVENUE BONDS (CONTINUED)

A summary of the derivative activity for the year ended June 30, 2024 was as follows:

	Notional Amount	Fair Value as of June 30, 2024	Change in Fair Value for Fiscal Year
2011 Water Refunding/Revenue Bonds Series A	$ 24,050	$ (831)	$ 546

Objective: In order to lower borrowing costs as compared to fixed-rate bonds, the Water Utility entered into an interest rate swap agreement in connection with its $59,000 2011 Water Refunding/Revenue Series A Bonds.

Terms: As of June 30, 2025, per the existing swap agreement, the Water Utility pays the counterparty a fixed payment and receives a variable payment computed as 62.68% of the Secured Overnight Financing Rate ("SOFR") one-month index plus 12 basis points. The swap has a notional amount equal to the remaining principal amount stated above. The notional value of the swap and principal amount of the associated debt decline by $2,375 to $3,950 until the debt is completely retired in fiscal year 2036. The bonds and the related swap agreement for the 2011 Water Refunding/Revenue Series A Bonds mature on October 1, 2035.

Replacement of LIBOR: As of July 1, 2023, LIBOR was no longer an appropriate benchmark interest rate for a derivative instrument that hedges the interest risk for taxable debt for purposes of GASB Statement 53.

As of June 30, 2025 and 2024, the rates were as follows:

Interest rate swap:	Terms	Rates
Fixed payment to counterparty	Fixed	3.20000 %
Variable payment from counterparty	62.68 SOFR + 12bps	(1.08784)%
Net interest rate swap payments		2.11216 %
Variable-rate bond coupon payments		0.89835 %
Synthetic interest rate on bonds		3.01051 %

Interest rate swap:	Terms	Rates
Fixed payment to counterparty	Fixed	3.20000 %
Variable payment from counterparty	62.68 SOFR + 12bps	(0.93099)%
Net interest rate swap payments		2.26901 %
Variable-rate bond coupon payments		0.81071 %
Synthetic interest rate on bonds		3.07972 %

Fair value: As of June 30, 2025 and 2024, in connection with the swap agreement, the transactions had a total fair value of $(1,185) and $(831), respectively. Because the coupons on the Water Utility's variable-rate bonds adjust to changing interest rates, the bonds do not have a corresponding fair value decrease. The fair value was developed by a pricing service using the zero-coupon method. This method calculates the future net settlement payments required by the swap, assuming that the current forward rates implied by the yield curve correctly anticipate future spot interest rates. These payments are then discounted using the spot rates implied by the current yield curve for hypothetical zero-coupon bonds due on the date of each future net settlement of the swap.

NOTE 4. LONG-TERM OBLIGATIONS (CONTINUED)

INTEREST RATE SWAPS ON REVENUE BONDS (CONTINUED)

Credit risk: As of June 30, 2025 and 2024, the Water Utility was not exposed to credit risk because the swap had a negative fair value. The swap counterparty, J.P. Morgan Chase Bank, N.A., was rated AA- by Standard & Poor's (S&P). To mitigate the potential for credit risk, the swap agreement requires the fair value of the swap to be collateralized by the counterparty with U.S. Government securities if the counterparty's rating decreases to negotiated trigger points. Collateral would be posted with a third-party custodian. At June 30, 2025 and 2024, there is no requirement for collateral posting for the outstanding swap.

Basis risk: As of June 30, 2025, the swap exposes the Water Utility to basis risk should the relationship between SOFR and the variable interest rates converge, changing the synthetic rate on the bonds. If a change occurs that results in the rates moving to convergence, the expected cost savings may not be realized.

Termination risk: The derivative contract uses the International Swap Dealers Association Master Agreement, which includes standard termination events, such as failure to pay and bankruptcy. The Schedule to the Master Agreement includes an "additional termination event." That is, a swap may be terminated by the Water Utility if the counterparty's credit quality falls below "BBB-" as issued by S&P. The Water Utility or the counterparty may terminate a swap if the other party fails to perform under the terms of the contract. If a swap is terminated, the variable-rate bond would no longer carry a synthetic interest rate. Also, if at the time of termination a swap has a negative fair value, the Water Utility would be liable to the counterparty for a payment equal to the swap's fair value.

Swap payments and associated debt: As of June 30, 2025 and 2024, the debt service requirements of the variable-rate debt and net swap payments, assuming current interest rates remain the same for their term, are summarized as follows. As rates vary, variable-rate bond interest payments and net swap payments will vary.

Fiscal Year Ending June 30,	Variable-Rate Bonds as of June 30, 2025			
	Principal	Interest	Interest Rate Swaps, Net	Total
2026	$ -	$ 235	$ 554	$ 789
2027	-	235	554	789
2028	-	235	554	789
2029	-	235	554	789
2030	3,275	212	497	3,984
2031-2035	16,825	574	1,350	18,749
2036-2040	3,950	10	23	3,983
Total	$ 24,050	$ 1,736	$ 4,086	$ 29,872

Fiscal Year Ending June 30,	Variable-Rate Bonds as of June 30, 2024			
	Principal	Interest	Interest Rate Swaps, Net	Total
2025	$ -	$ 208	$ 581	$ 789
2026	-	208	581	789
2027	-	208	581	789
2028	-	208	581	789
2029	-	208	581	789
2030-2034	16,275	651	1,822	18,748
2035-2039	7,775	51	143	7,969
Total	$ 24,050	$ 1,742	$ 4,870	$ 30,662

NOTE 4. LONG-TERM OBLIGATIONS (CONTINUED)

FINANCED PURCHASES

In fiscal year ended June 30, 2017, the Water Utility participated in the City's purchase financing program for the acquisition of water system heavy vehicles and equipment. The heavy vehicles and equipment financed purchases are for a ten-year term of annual payments with an interest rate of 2.36%. Gross proceeds of $2,305 were received for the financing.

As of June 30, 2025 and 2024, the total outstanding principal liability, including current portion, was $505 and $748, respectively. The annual payments for the life of the agreements are $260 annually through fiscal year ending June 30, 2027. As of June 30, 2025, total outstanding payments are $520, with $505 representing principal and $15 representing interest. As of June 30, 2024, total outstanding payments are $779, with $748 representing principal and $31 representing interest.

In fiscal year ended June 30, 2025, the Water Utility entered into a Capital Lease Agreement to finance the acquisition of Water Field Division vehicles and related equipment. The agreement is for a seven-year term with semi-annual payments and an interest rate of 4.15%. Gross proceeds of $4,814 were received for the financing.

As of June 30, 2025, the total outstanding principal liability, including current portion, was $4,514. The annual payments for the life of the agreement are $799 through fiscal year ending June 30, 2032. As of June 30, 2025, total outstanding payments are $5,197, with $4,514 representing principal and $683 representing interest.

NOTE 5. COMPENSATED ABSENCES

A liability for compensated absences is recognized as leave is earned and unused, to the extent that the leave is available for use by the employee in future periods. The liability reflects the amount expected to be settled through paid time-off or payment upon separation, and is measured using pay rates in effect at year-end.

The Water Utility implemented GASB Statement No. 101, *Compensated Absences* for the fiscal year ended June 30, 2025.

Below is a summary of changes in compensated absences for the Water Utility as of June 30, 2025 and 2024:

	Balance As of 6/30/2023	Net Increase/ (Decrease)*	Balance As of 6/30/2024	Net Increase/ (Decrease)	Balance As of 6/30/2025	Due Within One Year
Compensated absences	$ 2,485	$ 192	$ 2,677	$ 433	$ 3,110	$ 1,658

**Prior-year amounts have been reclassified to conform to the current year presentation*.

NOTE 6. EMPLOYEE RETIREMENT PLAN

PLAN DESCRIPTION

The Water Utility's employees participate in the City's Miscellaneous (non-safety) Plan (the Plan), an agent multiple employer public employee defined benefit pension plan. CalPERS provides retirement and disability benefits, annual cost-of-living adjustments, and death benefits to plan members and beneficiaries. CalPERS acts as a common investment and administrative agent for participating public entities within the State of California. CalPERS issues a publicly available financial report that includes financial statements and required supplementary information for the cost sharing plans that are administered by CalPERS. Benefit provisions and all other requirements are established by state statute and City ordinance. A copy of CalPERS' annual financial report may be obtained online at www.calpers.ca.gov. The Water Utility participates in the City's Miscellaneous (non-safety) Plan (the Plan).

FUNDING POLICY

The City has contributed at the actuarially determined rate provided by CalPERS' actuaries. Participants are required to contribute 8% of their annual covered salary. The City has a multiple tier retirement plan with benefits varying by plan. All permanent full-time and selected part-time employees are eligible for participation in CalPERS. Benefits vest after five years of service and are determined by a formula that considers the employee's age, years of service and salary. Under the Plan, the City pays the employees' contribution to CalPERS for employees hired on or before specific dates as follows:

- 1st Tier –
    - Unrepresented - The retirement formula is 2.7% at age 55 for employees hired on or before October 18, 2011. Unrepresented employees (Sr. Management, Management, Professional, Para-professional, Supervisory, Confidential, and Executive units, excluding the Chief of Police and the Fire Chief) are required to contribute 8% of their pensionable income.
    - SEIU – The retirement formula is 2.7% at age 55 for SEIU and SEIU Refuse employees hired before June 7, 2011. Employees are required to contribute 8% of their pensionable income.
    - IBEW - The retirement formula is 2.7% at age 55 for IBEW and IBEW Supervisory employees hired on or before October 18, 2011. Employees are required to contribute 8% of their pensionable income.
- 2nd Tier – The retirement formula is 2.7% at age 55, and:
    - Miscellaneous employees, IBEW, and IBEW Supervisory hired on or after October 19, 2011 pay their share (8%) of contributions.
    - SEIU and SEIU Refuse employees hired on or after June 7, 2011 pay their share (8%) of contributions.
- 3rd Tier – The retirement formula is 2% at age 62 for new members hired on or after January 1, 2013 and the employee must pay the normal cost to CalPERS, which is currently at 8.25%. Classic members (CalPERS members prior to 12/31/12) hired on or after January 1, 2013 may be placed in a different tier.

The contribution requirements of plan members and the City are established and may be amended by CalPERS.

NOTE 6. EMPLOYEE RETIREMENT PLAN (CONTINUED)

BENEFITS PROVIDED

CalPERS provides service retirement and disability benefits, annual cost of living adjustments and death benefits to plan members, who must be public employees and beneficiaries. Benefits are based on years of credited service, equal to one year of full-time employment. Members with five years of total service are eligible to retire at age 50 with statutorily reduced benefits. All members are eligible for non-duty disability benefits after five years of service. The death benefit is one of the following: the Basic Death Benefit, the 1959 Survivor Benefit Level III, or the Optional Settlement 2W Death Benefit. The cost of living adjustments for the Plan are applied as specified by the Public Employees' Retirement Law.

CONTRIBUTIONS

Section 20814(c) of the California Public Employees' Retirement Law requires that the employer contribution rates for all public employers be determined on an annual basis by the actuary and shall be effective on the July 1 following notice of a change in the rate. Funding contributions for the Plan is determined annually on an actuarial basis as of June 30 by CalPERS. The actuarially determined rate is the estimated amount necessary to finance the costs of benefits earned by employees during the year, with an additional amount to finance any unfunded accrued liability. The City is required to contribute the difference between the actuarially determined rate and the contribution rate of employees.

NET PENSION LIABILITY

The City's net pension liability for the Plan is measured as the total pension liability, less the pension plan's fiduciary net position. For fiscal year ended June 30, 2025, the net pension liability of the Plan is measured as of 2024, using an annual actuarial valuation as of June 30, 2023 rolled forward to 2024 using standard update procedures. For fiscal year ended 2024, the net pension liability of the Plan is measured as of June 30, 2023, using an annual actuarial valuation as of June 30, 2022 rolled forward to June 30, 2023 using standard update procedures. A summary of principal assumptions and methods used to determine the net pension liability is shown below.

ACTUARIAL ASSUMPTIONS

The total pension liabilities in the 2024 and 2023 actuarial valuations were determined using the following actuarial assumptions:

	Miscellaneous Current Year	Miscellaneous Prior Year
Valuation Date	June 30, 2023	June 30, 2022
Measurement Date	June 30, 2024	June 30, 2023
Actuarial Cost Method	Entry-Age Normal Cost Method	Entry-Age Normal Cost Method
Actuarial Assumptions		
Discount Rate	6.90%	6.90%
Inflation	2.30%	2.30%
Salary Increase	Varies by entry age and service	Varies by entry age and service
Mortality Rate Table[1]	Derived using CalPERS' membership data for all funds.	
Post Retirement Benefit Increase	The lesser of contract COLA or 2.30% until Purchasing Power Protection Allowance floor on purchasing power applies, 2.30% thereafter	The lesser of contract COLA or 2.30% until Purchasing Power Protection Allowance floor on purchasing power applies, 2.30% thereafter

[1]The mortality table used was developed based on CalPERS-specific data. The probabilities of mortality are based on the *2021 CalPERS Experience Study and Review of Actuarial Assumptions*. Mortality rates incorporate full generational mortality improvement using 80% of Scale MP-2020 published by the Society of Actuaries. For more details on this table, please refer to the 2021 experience study report from November 2021 that can be found on the CalPERS website.

NOTE 6. EMPLOYEE RETIREMENT PLAN (CONTINUED)

LONG-TERM EXPECTED RATE OF RETURN

The long-term expected rate of return on pension plan investments was determined using a building-block method in which expected future real rates of return (expected returns, net of pension plan investment expense and inflation) are developed for each major asset class.

In determining the long-term expected rate of return, CalPERS took into account both short-term and long-term market return expectations. Using historical returns of all of the funds' asset classes, expected compound (geometric) returns were calculated over the next 20 years using a building-block approach. The expected rate of return was then adjusted to account for assumed administrative expenses of 10 Basis points. The expected real rates of return by asset class are as follows:

Measurement Date
June 30, 2024

Asset Class (1)	Assumed Asset Allocation	Real Return(1),(2)
Global Equity - Cap-weighted	30.00%	4.54%
Global Equity - Non-Cap-weighted	12.00%	3.84%
Private Equity	13.00%	7.28%
Treasury	5.00%	0.27%
Mortgage-backed Securities	5.00%	0.50%
Investment Grade Corporates	10.00%	1.56%
High Yield	5.00%	2.27%
Emerging Market Debt	5.00%	2.48%
Private Debt	5.00%	3.57%
Real Assets	15.00%	3.21%
Leverage	-5.00%	-0.59%

(1) An expected inflation of 2.30% used for this period.

(2) Figures are based on the 2021 Asset Liability Management study.

Measurement Date
June 30, 2023

Asset Class (1)	Assumed Asset Allocation	Real Return(1),(2)
Global Equity - Cap-weighted	30.00%	4.54%
Global Equity - Non-Cap-weighted	12.00%	3.84%
Private Equity	13.00%	7.28%
Treasury	5.00%	0.27%
Mortgage-backed Securities	5.00%	0.50%
Investment Grade Corporates	10.00%	1.56%
High Yield	5.00%	2.27%
Emerging Market Debt	5.00%	2.48%
Private Debt	5.00%	3.57%
Real Assets	15.00%	3.21%
Leverage	-5.00%	-0.59%

(1) An expected inflation of 2.30% used for this period.

(2) Figures are based on the 2021 Asset Liability Management study.

NOTE 6. EMPLOYEE RETIREMENT PLAN (CONTINUED)

DISCOUNT RATE

The discount rate used to measure the total pension liability was 6.90% for measurement dates as of 2024 and 2023, respectively. The projection of cash flows used to determine the discount rate assumed that contributions from plan members will be made at the current member contribution rates and that contributions from employers will be made at statutorily required rates, actuarially determined. Based on those assumptions, the Plan's fiduciary net position was projected to be available to make all projected future benefit payments of current plan members. Therefore, the long-term expected rate of return on plan investments was applied to all periods of projected benefit payments to determine the total pension liability.

Changes of Benefit Terms - In 2022, SB 1168 increased the standard retiree lump sum death benefit from $500 to $2,000 for any death occurring on or after July 1, 2023. The impact, if any, is included in the changes of benefit terms.

CHANGES IN ASSUMPTIONS

In determining the long-term expected rate of return, CalPERS took into account long-term market return expectations as well as the expected pension fund cash flows. Projected returns for all asset classes were estimated, combined with risk estimates, and used to project compound (geometric) returns over the long term. The discount rate used to discount liabilities was informed by the long-term projected portfolio return. In addition, demographic assumptions and the inflation rate assumption were changed in accordance with the 2021 CalPERS Experience Study and Review of Actuarial Assumptions.

There were no assumption changes in valuation dated June 30, 2023 (2024 measurement date).

CHANGES IN THE NET PENSION LIABILITY (ASSET)

The changes in the Water Utility's proportionate share of the net pension liability/(asset) as of June 30, 2025 (measurement date 2024) and 2024 (measurement date June 30, 2023) for the Plan are as follows:

June 30, 2025	Net Pension Liability/ (Asset)	Proportion of the Plan
Proportion - Reporting date June 30, 2025 (Measurement Date June 30, 2024)	$ 17,238	9.21 %
Proportion - Reporting date June 30, 2024 (Measurement Date June 30, 2023)	14,455	9.33 %
Changes - Increase / (Decrease)	2,783	-0.12 %
June 30, 2024		
Proportion - Reporting date June 30, 2024 (Measurement Date June 30, 2023)	$ 14,455	9.33 %
Proportion - Reporting date June 30, 2023 (Measurement Date June 30, 2022)	12,854	9.76 %
Changes - Increase / (Decrease)	1,601	-0.43 %

NOTE 6. EMPLOYEE RETIREMENT PLAN (CONTINUED)

PENSION EXPENSES AND DEFERRED OUTFLOWS/INFLOWS OF RESOURCES RELATED TO PENSION

For the fiscal years ended June 30, 2025 and 2024, the Water Utility recognized pension expense of $5,638 and $4,463, respectively. At June 30, 2025 and 2024, the Water Utility reported deferred outflows/(inflows) of resources related to pension from the following sources:

	June 30, 2025		June 30, 2024	
	Deferred Outflows of Resources	Deferred Inflows of Resources	Deferred Outflows of Resources	Deferred Inflows of Resources
Pension contributions subsequent to measurement date	$ 2,531	$ -	$ 1,981	$ -
Change of assumptions	113	-	688	-
Difference between expected and actual expense	4,216	(102)	819	(618)
Net difference between projected and actual earnings on pension plan investments	2,437	-	6,650	-
Total	$ 9,297	$ (102)	$ 10,138	$ (618)

Deferred outflows of resources related to contributions subsequent to the measurement date reported in prior year was recognized as a reduction of the net pension liability in the year ended June 30, 2025 and 2024, respectively.

At June 30, 2025 and 2024, the Water Utility reported deferred outflows/(inflows) of resources related to pension to be recognized as pension expense as follows:

Year Ended June 30	Deferred Outflows/ (Inflows) of Resources
2026	$ 1,944
2027	5,489
2028	(41)
2029	(728)
Total	$ 6,664

Year Ended June 30	Deferred Outflows/ (Inflows) of Resources
2025	$ 1,667
2026	1,042
2027	4,632
2028	198
Total	$ 7,539

NOTE 6. EMPLOYEE RETIREMENT PLAN (CONTINUED)

PENSION EXPENSES AND DEFERRED OUTFLOWS/INFLOWS OF RESOURCES RELATED TO PENSION (CONTINUED)

On July 12, 2021, CalPERS reported a preliminary 21.3% net return on investments for fiscal year 2020-21. Based on the thresholds specified in CalPERS Funding Risk Mitigation policy, the excess return of 14.3% prescribed a reduction in investment volatility that corresponds to a reduction in the discount rate used for funding purposes of 0.20%, from 7.00% to 6.80%. Since CalPERS was in the final stages of the four-year Asset Liability Management (ALM) cycle, the board elected to defer any changes to the asset allocation until the ALM process concluded, and the board could make its final decision on the asset allocation in November 2021.

On November 17, 2021, the board adopted a new strategic asset allocation. The new asset allocation along with the new capital market assumptions, economic assumptions and administrative expense assumption support a discount rate of 6.90% (net of investment expense but without a reduction for administrative expense) for financial reporting purposes. This includes a reduction in the price inflation assumption from 2.50% to 2.30% as recommended in the November 2021 CalPERS Experience Study and Review of Actuarial Assumptions. This study also recommended modifications to retirement rates, termination rates, mortality rates and rates of salary increases that were adopted by the board. These new assumptions will be reflected in the GASB 68 accounting valuation reports for the June 30, 2022, measurement date.

Events Subsequent to June 30, 2023 valuation date (2024 measurement date) - There were no subsequent events that would materially affect the results in this disclosure.

SENSITIVITY OF THE NET PENSION LIABILITY (ASSET) TO CHANGES IN THE DISCOUNT RATE

The following presents the Water Utility’s proportionate share of the net pension liability of the Plan, calculated using the discount rate of 6.90% (measurement date June 30, 2024 and 2023), as well as what the Water Utility’s proportionate share of the net pension liability would be if it was calculated using a discount rate that is 1-percentage point lower or 1-percentage point higher than the current rate:

	Measurement Date June 30, 2024			Measurement Date June 30, 2023		
	Discount Rate -1% (5.90%)	Current Discount Rate (6.90%)	Discount Rate +1% (7.90%)	Discount Rate -1% (5.90%)	Current Discount Rate (6.90%)	Discount Rate +1% (7.90%)
Water Utility's proportionate share of the Plan's net pension liability/(asset)	$ 39,278	$ 17,238	$ (896)	$ 35,475	$ 14,455	$ (28,190)

Detailed information about the Plan’s fiduciary net position is available in the separately issued CalPERS financial reports.

NOTE 7. OTHER POST-EMPLOYMENT BENEFITS (OPEB)

PLAN DESCRIPTION

Employees of the Water Utility participate in the City's defined benefit OPEB plan, Retiree Health Plan, provides continuation of medical (including prescription drugs) and dental coverage benefits to retirees and surviving spouses in the form of an implied rate subsidy. The Retiree Health Benefits plan is a single employer defined benefit OPEB plan administered by the City. No assets are accumulated in a trust that meets the criteria in paragraph 4 of GASB Statement No. 75.

BENEFITS PROVIDED

Eligibility for continuation of coverage requires retirement from the City and CalPERS with at least 5 years of City service. The retiree is responsible for 100% of the premium cost for coverage, which is based on the blended experience of both the active and retired employees. The City is not required by law or contractual agreement to provide funding other than the pay-as-you-go amount necessary to provide current benefit to eligible retirees and beneficiaries. Retiree and spousal coverage terminates when the retiree becomes covered under another employer health plan, or when the retiree reaches Medicare eligibility age, which is currently age 65. However, retiree benefit continues to the surviving spouse if the retiree elects the CalPERS survivor annuity.

ACTUARIAL ASSUMPTIONS

The total OPEB liability was determined by actuarial valuation as of 2024 and 2023, using the following actuarial assumptions:

	Miscellaneous - Current Year	Miscellaneous - Prior Year
Valuation Date	June 30, 2023	June 30, 2023
Measurement Date	June 30, 2024	June 30, 2023
Actuarial Cost Method	Pay-as-you-go for implicit rate subsidy	Pay-as-you-go for implicit rate subsidy
Actuarial Assumptions		
Discount Rate	Bond Buyer 20 Index at June 30, 2023 resulting in a rate of 3.93%	Bond Buyer 20 Index at June 30, 2023 resulting in a rate of 3.65%
Inflation Rate	2.50% per annum	2.50% per annum
Payroll Increases	2.75% per year. Since benefits do not depend on salary (as they do for pensions), this assumption is only used to determine the accrual pattern of the Actuarial Present Value of Projected Benefit Payments.	2.75% per year. Since benefits do not depend on salary (as they do for pensions), this assumption is only used to determine the accrual pattern of the Actuarial Present Value of Projected Benefit Payments.
Mortality	2021 CalPERS Retiree Mortality Table for the appropriated population	2021 CalPERS Retiree Mortality Table for the appropriated population
Healthcare Trend Rates	Medical trend in future years has been updated to 4.00% for all years.	Medical trend in future years has been updated to 4.00% for all years.

CHANGES OF ASSUMPTIONS

In 2024, the discount rate was changed from 3.65% to 3.93%. In 2023, the discount rate was changed from 3.54% to 3.65%.

NOTE 7. OTHER POST-EMPLOYMENT BENEFITS (OPEB) (CONTINUED)

SENSITIVITY OF TOTAL OPEB LIABILITY TO CHANGES IN HEALTHCARE COST TREND RATES

The following presents the Water Utility's proportionate share of the City's total OPEB liability, calculating using the healthcare trend rate of 4.00% for measurement date as of June 30, 2024 and June 30, 2023, as well as what the Water Utility's total OPEB liability would be if it was calculated using a healthcare cost trend rate that is 1-percentage-point lower or 1-percentage-point higher than the current rate:

	Measurement Date June 30, 2024			Measurement Date June 30, 2023		
	1% Decrease	Current healthcare cost trend rate 4%	1% Increase	1% Decrease	Current healthcare cost trend rate 4%	1% Increase
Water Utility's proportionate share of the total OPEB liability	$ 3,090	$ 4,404	$ 4,054	$ 2,924	$ 4,265	$ 3,793

SENSITIVITY OF TOTAL OPEB LIABILITY TO CHANGES IN DISCOUNT RATES

The following presents the Water Utility's proportionate share of the City's total OPEB liability, calculating using the discount rate of 3.93% and 3.65% for measurement date as of 2024 and 2023 respectively, as well as what the Water Utility's total OPEB liability would be if it was calculated using a discount rate that is 1-percentage-point lower or 1-percentage-point higher than the current rate:

	Measurement Date June 30, 2024			Measurement Date June 30, 2023		
	1% Decrease (2.93%)	Current Discount Rate (3.93%)	1% Increase (4.93%)	1% Decrease (2.65%)	Current Discount Rate (3.65%)	1% Increase (4.65%)
Water Utility's proportionate share of total OPEB liability	$ 3,861	$ 4,404	$ 3,246	$ 3,627	$ 4,265	$ 3,042

CHANGE IN TOTAL OPEB LIABILITY

For fiscal year ended June 30, 2025 and 2024, the Water Utility recognized total OPEB expense of $203 and $173 respectively. The following table shows the change in the Water Utility's proportionate share of the City's total OPEB liability for the year ended June 30, 2025 (measurement date 2024) and the year ended 2024 (measurement date June 30, 2023):

June 30, 2025	Total OPEB Liability	Proportion of the City
Proportion - Reporting date June 30, 2025 (Measurement Date June 30, 2024)	$ 4,404	6.96 %
Proportion - Reporting date June 30, 2024 (Measurement Date June 30, 2023)	4,265	6.82 %
Changes - Increase / (Decrease)	139	0.14 %
June 30, 2024		
Proportion - Reporting date June 30, 2024 (Measurement Date June 30, 2023)	$ 4,265	6.82 %
Proportion - Reporting date June 30, 2023 (Measurement Date June 30, 2022)	4,043	8.89 %
Changes - Increase / (Decrease)	222	-2.07 %

NOTE 7. OTHER POST-EMPLOYMENT BENEFITS (OPEB) (CONTINUED)

DEFERRED OUTFLOWS/INFLOWS OF RESOURCES RELATED TO OPEB

At June 30, 2025 and 2024, the Water Utility reported deferred outflows/(inflows) of resources related to OPEB from the following sources:

	Deferred Outflows of Resources	Deferred Inflows of Resources
Difference between expected and actual expense	$ 80	$ (189)
Change of assumptions	310	(598)
Contributions subsequent to measurement date	137	-
Total	$ 527	$ (787)

	Deferred Outflows of Resources	Deferred Inflows of Resources
Difference between expected and actual expense	$ 89	$ (223)
Change of assumptions	403	(583)
Contributions subsequent to measurement date	118	-
Total	$ 610	$ (806)

At June 30, 2025 and 2024, the Water Utility reported deferred outflows/(inflows) of resources related to OPEB to be recognized as OPEB expense as follows:

Year Ended June 30	Deferred Outflows/ (Inflows) of Resources
2026	$ 3
2027	7
2028	7
2029	(88)
2030	(88)
Thereafter	(238)
Total	$ (397)

Year Ended June 30	Deferred Outflows/ (Inflows) of Resources
2025	$ (5)
2026	13
2027	16
2028	16
2029	(79)
Thereafter	(275)
Total	$ (314)

NOTE 8. RESTRICTED NET POSITION

Pursuant to applicable bond indentures, a reserve for debt service has been established by restricting assets and reserving a portion of net position. Bond indentures for the Water Utility's revenue and refunding bonds require debt service reserves that equate to the maximum annual debt service required in future years and bond service reserves of three months interest and nine months principal due in the next fiscal year. Variable rate revenue and refunding bonds require 110% of the monthly accrued interest to be included in the reserve. Certain issues have no debt service reserve requirements (2009B, 2011A, 2019A and 2022A). See Note 4 for further discussion related to the Water Utility's debt issuances.

Pursuant to the Eleventh Supplemental Resolution, as stated in the Water Revenue Bonds, Issue of 2022A indentures, the Fiscal Agent will establish, maintain and hold in trust a separate account designated as the "2022 Water Revenue Bond Issue Rebate Account". All money at any time deposited in the 2022A Water Revenue Bond Issue Rebate Account will be held by the Fiscal Agent in the restricted account for payment to the United States Treasury. Within 55 days of the end of each bond year, the Water Utility will calculate the amount of rebatable arbitrage. The Fiscal Agent will pay to the United States Treasury, not later than 60 days after the end of the 5th bond year; and each applicable 5th bond year thereafter, an amount equal to at least 90% of the Rebatable Arbitrage calculated as of the end of such bond year; not later than 60 days after the payment of all of the 2022A Bonds, an amount equal to 100% of the Rebatable Arbitrage calculated as of the end of such applicable bond year, and any income attributable to the Rebatable Arbitrage (Section 148(f) of the Code and Section 1.148 3 of the Treasury Regulations). During the interim computation period from 12/1/2022 through 12/1/2024, the cumulative excess Arbitrage Rebate Liability in the amount of $1,337 was computed. As of June 30, 2025, the Water Utility recorded an arbitrage liability related to the 2022 Water Revenue Bonds Series A. See Note 4 for further discussion related to the Water Utility's debt issuances.

In the Annual Valuation Report as of June 30, 2021, CalPERS reported an investment return of 21.3%. These positive returns contributed to the reduction of the unfunded accrued liability (UAL). The City did not eliminate the budgeted UAL payments during the amendment of the fiscal year 2023-24 budget, but rather redirected those budgeted payments the respective funds' restricted cash and investments held at fiscal agent and restricted fund balance for future UAL costs. See Note 6 for further discussion related to the UAL.

NOTE 9. CONSTRUCTION COMMITMENTS

As of June 30, 2025, the Water Utility had commitments (encumbrances) of approximately $13,779 with respect to ongoing capital projects, of which $9,819 is expected to be funded by bonds, and $3,960 to be funded by unrestricted reserves.

NOTE 10. LITIGATION

The Water Utility is a defendant in various lawsuits arising in the normal course of business. Present lawsuits and other claims against the Water Utility are incidental to the ordinary course of operations of the Water Utility and are largely covered by the City's self-insurance program. In the opinion of management and the City Attorney, such claims and litigation will not have a materially adverse effect upon the financial position or results of operations of the Water Utility.

CITY OF RIVERSIDE V. BLACK & DECKER (U.S.), INC.

The Water Utility is a plaintiff in a lawsuit against several entities that either owned or leased a property site in the City of Colton and City of Rialto that is contaminated by perchlorate. The lawsuit was filed March 31, 2009. On May 24, 2018, the State trial court dismissed the action, with prejudice, for failure to join the federal Department of Defense, with instructions to refile the lawsuit in federal court and include the Department of Defense as a party. The City has appealed such dismissal, and on May 6, 2020, the appellate court overturned the trial court's dismissal. The appellate court remanded the case back to the trial court and the parties are now waiting for the trial court to set a trial date. The City has reached a settlement with two of the defendants, Trojan Fireworks Company and Zambelli, and those defendants have been dismissed from the lawsuit. On February 8, 2025, the City dismissed its lawsuit, without prejudice, and will refile when perchlorate levels increase in the affected wells.

PONGS V. CITY OF RIVERSIDE ("PONGS I")

On December 16, 2019, a lawsuit entitled Pongs v. City of Riverside ("Pongs I") was filed against the City challenging the City's Water Rate WA-12, "Agricultural Water," alleging that the City is overcharging customers for service under this rate in violation of Article XIIID, Section 6 of the California Constitution. The plaintiff is seeking that the court invalidate Water Rate WA-12 and refund all to all WA-12 customers monies collected under that rate. A hearing date for the first phase of the trial, on liability, has been scheduled for November 17, 2021. This lawsuit has been stayed pending the resolution of another lawsuit challenging the City's Water General Fund Transfer, entitled Simpson v. City of Riverside (Simpson I, as referenced below).

PONGS V. CITY OF RIVERSIDE ("PONGS II")

On December 22, 2022, a lawsuit entitled Pongs v. City of Riverside ("Pongs II") was filed against the City. This case is a reverse validation action filed by Carl Pongs and Richard Moslenko against the City challenging under Proposition 218 the City's issuance of bonds in 2022 secured by the water rates. On August 18, 2023, the trial court ruled in favor of the City, holding that there was no Proposition 218 violation. On February 24, 2025, the appellate court ruled in favor of the City and on April 7, 2025. Plaintiff filed a petition for review with the California Supreme Court, which was denied. The City has filed for recovery of costs in the amount of $2,677.96.

PONGS V. CITY OF RIVERSIDE ("PONGS III")

On January 26, 2024, a lawsuit entitled Pongs v. City of Riverside ("Pongs III") was filed against the City. In late 2023, the City of Riverside (the "City") adopted Resolution No. 24042 setting new water rates for fiscal years 2023-24 to 2027-28. Pongs III is a reverse validation action challenging the validity of the new rates. Pongs alleges multiple violations of Article XIII D (also referred herein as Proposition 218) including, *inter alia,* illegal transfers of water rate revenue from the City's water utility into the General Fund, invalid tiered rate structures, and improper spending of water rate revenue on categories unrelated to the provision of water service. This lawsuit has been stayed pending the resolution of another lawsuit challenging the City's Water General Fund Transfer, entitled Simpson v. City of Riverside (Simpson I, as referenced below).

PONGS ET AL. V. CITY OF RIVERSIDE ET AL. ("PONGS IV")

On March 3, 2023, a lawsuit entitled Pongs et al. v. City of Riverside et al. was filed against the City by a water customer as an individual and seeking class action certification, alleging that the City improperly acquired shares in the Gage Canal Company in breach of the Gage Canal Operating Agreement entered into on June 9, 1965. Plaintiff seeks return of the Gage Canal shares to all shareholders improperly divested of shares and that the Court enjoin the City from continuing its current practice to acquire ownership of Gage Canal shares. On December 19, 2024, the Court ruled in favor of the City. Pongs appealed on March 4, 2025, and the case has been transferred to Division 1 of the 4th Appellate District, which is in San Diego. No briefing schedule has been set.

NOTE 10. LITIGATION (CONTINUED)

SIMPSON V. CITY OF RIVERSIDE ("SIMPSON I")

On December 19, 2019, a class action lawsuit entitled Simpson v. City of Riverside was filed against the City alleging that the City is overcharging customers for water utility service in violation of Article XIIID, Section 6 of the California Constitution, on the grounds that the City is transferring 11.5% of water utility revenues to the City's general fund. The transfer, also known as the "General Fund Transfer," was approved by voters on June 4, 2013, as a general tax. The plaintiff is seeking refunds for all customers for monies collected in violation and also that the court set aside the voter's 2013 approval of the General Fund Transfer. The trial was bifurcated into two phases, liability and damages. The Court issued its ruling on the liability phase on August 17, 2023, finding that the City's water rates violated Article XIID, Section 6 of the California Constitution. of the California Constitution. The trial on damages was conducted on September 6, 2024 and on December 12, 2024, the trial court ruled that the City is required to refund ratepayers for the Water GFT. Plaintiff submitted a proposed judgment to the court for a refund to ratepayers in the amount of $46,244,417.89 and the City filed objections to the judgment. Plaintiffs' motion for attorneys' fees is scheduled for August 27, 2025 and no judgment has been issued.

SIMPSON V. CITY OF RIVERSIDE ("SIMPSON II")

On January 26, 2024, a lawsuit entitled Simpson v. City of Riverside ("Simpson II") was filed against the City. In late 2023, the City of Riverside (the "City") adopted Resolution No. 24042 setting new water rates for fiscal years 2023-24 to 2027-28. Simpson II is a reverse validation action challenging the validity of the new rates. Pongs alleges multiple violations of Article XIII D (also referred herein as Proposition 218) including, *inter alia,* illegal transfers of water rate revenue from the City's water utility into the General Fund, invalid tiered rate structures, and improper spending of water rate revenue on categories unrelated to the provision of water service. No hearing date has been set. This lawsuit has been stayed pending the resolution of another lawsuit challenging the City's Water General Fund Transfer, entitled Simpson v. City of Riverside (Simpson I, as referenced above).

CITY OF RIVERSIDE V. 3M COMPANY, ET AL.

The Water Utility is a plaintiff in a lawsuit against several entities over contamination of its water supply wells with synthetic per- and polyfluoroalkyl substances ("PFAS"). The lawsuit was filed July 26, 2021, as part of a multidistrict litigation proceeding consolidated before a federal judge in Charleston, South Carolina. No trial date has been set.

CITY OF RIVERSIDE V. SHELL OIL COMPANY, ET AL.

The Water Utility is a plaintiff in a lawsuit against several entities over contamination of its water supply wells with 1, 2, 3, -Trichloropropane ("TCP"). The lawsuit was filed December 4, 2020, in the superior court in San Francisco. No trial date has been set.

NOTE 11. LEASES AND SUBSCRIPTION-BASED INFORMATION TECHNOLOGY ARRANGEMENTS

LEASES PAYABLE

Leases are financings of the right-to-use an underlying asset and a lessee is required to recognize a lease liability and an intangible lease asset.

The Water Utility has consistently maintained 4 leases as Lessee for the use of various pieces of machinery and equipment for the fiscal years ended June 30, 2025 and 2024. The Water Utility is required to make principal and interest payments through fiscal year 2029. As of June 30, 2025 and 2024, the value of the lease liability was $24 and $21, respectively. The leases had an interest rate of 2.50% to 2.80% and 0.52% to 2.50% for the fiscal years ended June 30, 2025 and 2024, respectively. The value of the lease assets was $29 and $26, with accumulated amortization of $6 and $6, for the fiscal years ended June 30, 2025 and 2024, respectively, as shown on the Asset Class activities table found below.

	Amount of Lease Assets by Major Classes of Underlying Asset June 30, 2025	
Asset Class	**Lease Asset Value**	**Accumulated Amortization**
Machinery and equipment	$ 29	$ (6)
Total	$ 29	$ (6)

	Amount of Lease Assets by Major Classes of Underlying Asset June 30, 2024	
Asset Class	**Lease Asset Value**	**Accumulated Amortization**
Machinery and equipment	$ 26	$ (6)
Total	$ 26	$ (6)

The following is a summary of changes in leases liability during the fiscal years ended June 30, 2025 and 2024:

	Balance As of 6/30/2023	Additions	Reclass	Reductions	Balance As of 6/30/2024	Additions	Reclass	Reductions	Balance As of 6/30/2025	Due Within One Year
Lease Liability	$ 12	$ 21	$ -	$ (12)	$ 21	$ 8	$ -	$ (5)	$ 24	$ 6

NOTE 11. LEASES AND SUBSCRIPTION-BASED INFORMATION TECHNOLOGY ARRANGEMENTS (CONTINUED)

As of June 30, 2025, lease liability principal and interest payments consist of the following:

Fiscal Year	Principal Payments	Interest Payments	Total Payments
2026	$ 6	$ 1	$ 7
2027	6	-	6
2028	6	-	6
2029	5	-	5
2030	1	-	1
Total	$ 24	$ 1	$ 25

As of June 30, 2024, lease liability principal and interest payments consist of the following:

Fiscal Year	Principal Payments	Interest Payments	Total Payments
2025	$ 5	$ 1	$ 6
2026	4	-	4
2027	4	-	4
2028	4	-	4
2029	4	-	4
Total	$ 21	$ 1	$ 22

LEASES RECEIVABLE

Leases are financings of the right-to-use an underlying asset and a lessor is required to recognize a lease receivable and a deferred inflow of resources.

The Water Utility had 25 and 23 leases as a Lessor for the use of various pieces of land and buildings for the fiscal years ended June 30, 2025 and 2024, respectively. At June 30, 2025 and 2024, the terms of these leases consistently ranged from 3 to 55 years beginning on the contract commencement date. For the fiscal years ended of June 30, 2025 and 2024, the value of the lease receivables was $90,059 and $89,569, respectively, with interest rates consistently ranging from 0.52% to 3.35%. As of June 30, 2025 and 2024, the value of the deferred inflow of resources was $99,839 and $101,497, with recognized lease revenue of $3,048 and $2,928, respectively.

NOTE 11. LEASES AND SUBSCRIPTION-BASED INFORMATION TECHNOLOGY ARRANGEMENTS (CONTINUED)

LEASES RECEIVABLE (CONTINUED)

As of June 30, 2025, lease receivable principal and interest payments consist of the following:

Fiscal Year	Principal Payments	Interest Payments	Total Payments
2026	$ 952	$ 1,724	$ 2,676
2027	650	1,721	2,371
2028	378	1,734	2,112
2029	394	1,737	2,131
2030	381	1,744	2,125
2031-2035	1,765	8,536	10,301
2036-2040	3,031	7,894	10,925
2041-2045	8,507	7,073	15,580
2046-2050	9,886	6,237	16,123
2051-2055	11,589	5,256	16,845
2056-2060	14,132	4,098	18,230
2061-2065	16,149	2,718	18,867
2066-2070	17,253	1,183	18,436
2071-2075	4,992	121	5,113
Total	$ 90,059	$ 51,776	$ 141,835

As of June 30, 2024, lease receivable principal and interest payments consist of the following:

Fiscal Year	Principal Payments	Interest Payments	Total Payments
2025	$ 847	$ 1,700	$ 2,547
2026	873	1,697	2,570
2027	570	1,696	2,266
2028	295	1,710	2,005
2029	310	1,714	2,024
2030-2034	1,327	8,525	9,852
2035-2039	2,049	7,990	10,039
2040-2044	7,798	7,208	15,006
2045-2049	9,369	6,384	15,753
2050-2054	11,236	5,443	16,679
2055-2059	13,467	4,340	17,807
2060-2064	15,795	3,007	18,802
2065-2069	17,502	1,497	18,999
2070-2074	8,131	234	8,365
Total	$ 89,569	$ 53,145	$ 142,714

NOTE 11. LEASES AND SUBSCRIPTION-BASED INFORMATION TECHNOLOGY ARRANGEMENTS (CONTINUED)

SUBSCRIPTION-BASED INFORMATION TECHNOLOGY ARRANGEMENTS PAYABLE

The Water Utility had no subscription-based information technology arrangements (SBITA) for the use of various software for the fiscal year ended June 30, 2025 and 2 SBITAs for the fiscal year ended June 30, 2024. The Water Utility is required to make principal and interest payments through fiscal year 2025. An initial lease liability was recorded in the amount of $32. As of June 30, 2025 and 2024, the value of the subscription liability was $0 and $2, respectively, with a consistent interest rate of 0.52%. As of June 30, 2025 and 2024, the value of the subscription assets was $0 and $33, with accumulated amortization of $0 and $25, respectively.

During fiscal year 2025, the remaining SBITA asset and liability were fully amortized. As a result, no SBITA balance was outstanding as of June 30, 2025, and only fiscal year 2024 activity and balances are presented in the following tables.

As of June 30, 2024, the Asset Class activities tables were as follows:

	Amount of SBITA Assets by Major Classes of Underlying Asset June 30, 2024	
Asset Class	**SBITA Asset Value**	**Accumulated Amortization**
Software	$ 33	$ (25)
Total	$ 33	$ (25)

The following is a summary of changes in SBITA liability during the fiscal years ended June 30, 2025 and 2024:

	Balance As of 6/30/2023	Additions	Reclass	Reductions	Balance As of 6/30/2024	Additions	Reclass	Reductions	Balance As of 6/30/2025	Due Within One Year
SBITA Liability	$ 17	$ -	$ -	$ (15)	$ 2	$ -	$ -	$ (2)	$ -	$ -

As of June 30, 2024, SBITA liability principal and interest payments consist of the following:

Fiscal Year	Principal	Interest	Total Payments
2025	$ 2	$ -	$ 2
Total	$ 2	$ -	$ 2

NOTE 12. RESTATEMENT OF BEGINNING NET POSITION

A restatement was recorded to decrease the Water Utility's net position, including Water Conservation Programs. This restatement reflects corrections to construction in progress of $(10,781), accumulated depreciation related to utility plant of $(1,058), and customer deposits of $(813). Additionally, the restatement decreases the previously reported change in net position by $(1,797).

The effect of the restatement is shown in the tables below:

	June 30, 2023 as Previously Reported	Error Correction	June 30, 2023 as Restated
Net Position	$ 330,029	$ (10,855)	$ 319,174

	June 30, 2024 as Previously Reported	Error Correction	June 30, 2024 as Restated
Change in Net Position	$ 9,642	$ (1,797)	$ 7,845

WATER UTILITY
SCHEDULE OF PROPORTIONATE SHARE OF THE NET PENSION LIABILITY
AS OF JUNE 30, FOR THE LAST TEN FISCAL YEARS (1)
(amounts expressed in thousands)

Reporting period	**2025**	**2024**	**2023**	**2022**	**2021**
Measurement period	**2024**	**2023**	**2022**	**2021**	**2020**
Water Utility's Proportion of the Net Pension Liability	9.21%	9.33%	9.76%	9.93%	10.16%
Water Utility's Proportionate Share of the Net Pension Liability	$ 17,238	$ 14,455	$ 12,854	$ (8,809)	$ 12,203
Water Utility's Covered Payroll	$ 14,487	$ 13,258	$ 12,694	$ 13,034	$ 13,364
Water Utility's Proportionate Share of the Net Pension Liability as a Percentage of Covered Payroll	118.99%	109.03%	101.26%	-67.59%	91.31%
Water Utility's Proportionate Share of the Fiduciary Net Position as a Percentage of the Water Utility's Total Pension Liability	89.53%	90.73%	91.80%	105.72%	91.95%

Notes to Schedule:

Benefit Changes:
There were no changes in benefits.

Changes in Assumptions:
From fiscal year June 30, 2015 to June 30, 2016:
GASB 68, paragraph 68 states that the long-term expected rate of return should be determined net of pension plan investment expense but without reduction for pension plan administrative expense. The discount rate of 7.50% used for the June 30, 2014 measurement date was net of administrative expenses. The discount rate of 7.65% used for the June 30, 2015 measurement date is without reduction of pension plan administrative expense.
From fiscal year June 30, 2016 to June 30, 2017:
There were no changes in assumptions.
From fiscal year June 30, 2017 to June 30, 2018:
The discount rate was reduced from 7.65% to 7.15%.
From fiscal year June 30, 2018 to June 30, 2022:
There were no significant changes in assumptions.
From fiscal year June 30, 2022 to June 30, 2023:
The discount rate and long-term rate of return decreased from 7.15% to 6.90% and the inflation rate decreased from 2.50% to 2.30%.
From fiscal year June 30, 2023 to June 30, 2024:
There were no significant changes in assumptions.
From fiscal year June 30, 2024 to June 30, 2025:
There were no significant changes in assumptions.

WATER UTILITY
SCHEDULE OF PROPORTIONATE SHARE OF THE NET PENSION LIABILITY (CONTINUED)
AS OF JUNE 30, FOR THE LAST TEN FISCAL YEARS (1)
(amounts expressed in thousands)

Reporting period	**2020**	**2019**	**2018**	**2017**	**2016**
Fiscal Year Ended	**2019**	**2018**	**2017**	**2016**	**2015**
Water Utility's Proportion of the Net Pension Liability	10.90%	11.03%	11.44%	11.14%	11.59%
Water Utility's Proportionate Share of the Net Pension Liability	$ 31,840	$ 30,737	$ 38,880	$ 34,465	$ 28,257
Water Utility's Covered Payroll	$ 14,044	$ 13,455	$ 13,457	$ 13,197	$ 12,853
Water Utility's Proportionate Share of the Net Pension Liability as a Percentage of Covered Payroll	226.72%	228.44%	288.93%	261.15%	219.85%
Water Utility's Proportionate Share of the Fiduciary Net Position as a Percentage of the Water Utility's Total Pension Liability	79.57%	79.64%	75.23%	75.47%	79.93%

Notes to Schedule:

Benefit Changes:
There were no changes in benefits.

Changes in Assumptions:
From fiscal year June 30, 2015 to June 30, 2016:
GASB 68, paragraph 68 states that the long-term expected rate of return should be determined net of pension plan investment expense but without reduction for pension plan administrative expense. The discount rate of 7.50% used for the June 30, 2014 measurement date was net of administrative expenses. The discount rate of 7.65% used for the June 30, 2015 measurement date is without reduction of pension plan administrative expense.
From fiscal year June 30, 2016 to June 30, 2017:
There were no changes in assumptions.
From fiscal year June 30, 2017 to June 30, 2018:
The discount rate was reduced from 7.65% to 7.15%.
From fiscal year June 30, 2018 to June 30, 2022:
There were no significant changes in assumptions.
From fiscal year June 30, 2022 to June 30, 2023:
The discount rate and long-term rate of return decreased from 7.15% to 6.90% and the inflation rate decreased from 2.50% to 2.30%.
From fiscal year June 30, 2023 to June 30, 2024:
There were no significant changes in assumptions.
From fiscal year June 30, 2024 to June 30, 2025:
There were no significant changes in assumptions.

WATER UTILITY
SCHEDULE OF CONTRIBUTIONS
AS OF JUNE 30, FOR THE LAST TEN FISCAL YEARS
(amounts expressed in thousands)

	2025	2024	2023	2022	2021
Contractually Required Contribution (Actuarially Determined)	$ 2,531	$ 1,956 (6)	$ 2,718	$ 2,667	$ 2,610
Contributions in Relation to the Actuarially Determined Contributions	(2,531)	(1,981)	(2,718)	(2,667)	(2,610)
Contribution Deficiency (Excess)	$ -	$ -	$ -	$ -	$ -
Covered Payroll	$ 15,807	$ 14,487	$ 13,258	$ 12,694	$ 13,034
Contributions as a Percentage of Covered Payroll	16.01%	13.50%	20.50%	21.01%	20.02%

Notes to Schedule:

Valuation Date	6/30/2022	6/30/2021	6/30/2020	6/30/2019	6/30/2018
Methods and Assumptions Used to Determine Contribution Rates:					
Actuarial Cost Method	Entry Age	Entry Age	Entry Age	Entry Age	Entry Age
Amortization Method	(1)	(1)	(1)	(1)	(1)
Asset Valuation Method	Fair Value	Fair Value	Fair Value	Fair Value	Fair Value
Inflation	2.300%	2.300%	2.300%	2.500%	2.500%
Salary Increases	(2)	(2)	(2)	(2)	(2)
Investment Rate of Return	6.80% (3)	6.80% (3)	6.80% (3)	7.00% (3)	7.00% (3)
Retirement Age	(4)	(4)	(4)	(4)	(4)
Mortality	(5)	(5)	(5)	(5)	(5)

(1) Level percentage of payroll, closed
(2) Depending on age, service, and type of employment
(3) Net of pension plan investment expense, including inflation
(4) Classic: 50-67 and PEPRA: 52-67
(5) Mortality assumptions are based on mortality rates resulting from the most recent CalPERS Experience Study adopted by the CalPERS Board.
(6) This amount was projected in FY 2023-2024. Now that actual data is available, the number has been updated.

WATER UTILITY
SCHEDULE OF CONTRIBUTIONS
AS OF JUNE 30, FOR THE LAST TEN FISCAL YEARS
(amounts expressed in thousands)

	2020	2019	2018	2017	2016
Contractually Required Contribution (Actuarially Determined)	$ 3,952	$ 3,758	$ 3,304	$ 3,083	$ 2,771
Contributions in Relation to the Actuarially Determined Contributions	(24,313)	(3,758)	(3,304)	(3,486)	(3,277)
Contribution Deficiency (Excess)	$ (20,361)	$ -	$ -	$ (403)	$ (506)
Covered Payroll	$ 13,364	$ 14,044	$ 13,455	$ 13,457	$ 13,197
Contributions as a Percentage of Covered Payroll	29.58%	26.76%	24.56%	22.91%	21.00%

Notes to Schedule:

Valuation Date	6/30/2017	6/30/2016	6/30/2015	6/30/2014	6/30/2013
Methods and Assumptions Used to Determine Contribution Rates:					
Actuarial Cost Method	Entry Age	Entry Age	Entry Age	Entry Age	Entry Age
Amortization Method	(1)	(1)	(1)	(1)	(1)
Asset Valuation Method	Fair Value	Fair Value	Fair Value	Fair Value	Fair Value
Inflation	2.625%	2.75%	2.75%	2.75%	2.75%
Salary Increases	(2)	(2)	(2)	(2)	(2)
Investment Rate of Return	7.25% (3)	7.375% (3)	7.50% (3)	7.50% (3)	7.50% (3)
Retirement Age	(4)	(4)	(4)	(4)	(4)
Mortality	(5)	(5)	(5)	(5)	(5)

(1) Level percentage of payroll, closed
(2) Depending on age, service, and type of employment
(3) Net of pension plan investment expense, including inflation
(4) Classic: 50-67 and PEPRA: 52-67
(5) Mortality assumptions are based on mortality rates resulting from the most recent CalPERS Experience Study adopted by the CalPERS Board.
(6) This amount was projected in FY 2023-2024. Now that actual data is available, the number has been updated.

WATER UTILITY
SCHEDULE OF CHANGES IN TOTAL OPEB LIABILITY AND RELATED RATIOS
AS OF JUNE 30, FOR THE LAST EIGHT FISCAL YEARS (1)
(amounts expressed in thousands)

Reporting period	**2025**	**2024**	**2023**	**2022**
Measurement period	**2024**	**2023**	**2022**	**2021**
Water Utility's Proportion of the Net OPEB Liability	6.96%	6.82%	8.89%	8.79%
Water Utility's Proportionate Share of the Net OPEB Liability	$ 4,404.00	$ 4,265	$ 4,043	$ 4,286
Water Utility's Covered Payroll	$ 15,015.27	$ 14,265	$ 18,065	$ 17,342
Water Utility's Proportionate Share of the Net OPEB Liability as a Percentage of Covered Payroll	29.33%	29.90%	22.38%	24.71%

Reporting period	**2021**	**2020**	**2019**	**2018**
Measurement period	**2020**	**2019**	**2018**	**2017**
Water Utility's Proportion of the Net OPEB Liability	8.70%	8.76%	9.19%	9.30%
Water Utility's Proportionate Share of the Net OPEB Liability	$ 4,550	$ 4,382	$ 3,524	$ 3,410
Water Utility's Covered Payroll	$ 16,665	$ 16,291	$ 15,702	$ 15,890
Water Utility's Proportionate Share of the Net OPEB Liability as a Percentage of Covered Payroll	27.30%	26.90%	22.44%	21.46%

(1) Historical information is required only for the measurement periods for which GASB 75 is applicable. Fiscal Year 2018 was the first year of implementation. Future years' information will be displayed up to 10 years as information becomes available.

Notes to Schedule:
Changes in assumptions: For the measurement period ending June 30, 2024, the discount rate was changed from 3.65 percent to 3.93 percent. There are no asset accumulated in a trust that meets the criteria of GASB codification P22.101 or P52.101 to pay related benefits for the OPEB plan.

WATER UTILITY
KEY HISTORICAL OPERATING DATA

Fiscal Year	2024/25	2023/24	2022/23	2021/22	2020/21
WATER SUPPLY (ACRE FEET)					
Potable water production[1]	65,578	59,863	60,185	68,054	72,215
Percentage pumped (%)[2]	100	100	100	100	100
System peak day (gallons)[3]	84,700,000	82,500,000	81,800,000	82,700,000	91,900,000
WATER USE					
Number of meters as of year-end:					
Residential	60,179	60,041	59,907	59,876	59,782
Commercial/Industrial	6,225	6,170	6,175	6,153	6,080
Other	368	359	359	343	336
Total	66,772	66,570	66,441	66,372	66,198
CCF* sales:					
Residential	14,578,750	12,975,991	13,078,242	15,362,908	16,149,357
Commercial/Industrial	9,900,207	8,834,297	9,003,457	10,245,377	10,069,176
Other	919,682	733,429	764,265	870,928	835,300
Subtotal	25,398,639	22,543,717	22,845,964	26,479,213	27,053,833
Wholesale	366,488	467,726	821,502	366,370	1,571,549
Total	25,765,127	23,011,443	23,667,466	26,845,583	28,625,382

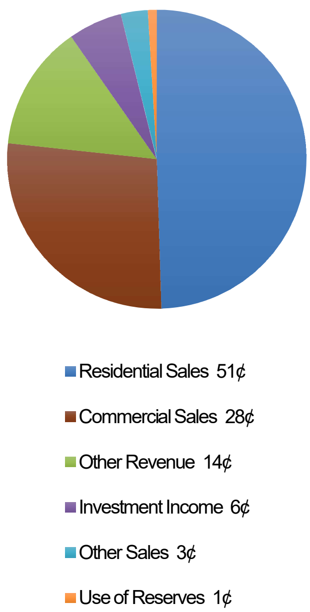
*1 CCF equals 100 cubic feet

	2024/25	2023/24	2022/23	2021/22	2020/21
WATER FACTS					
Average annual CCF per residential customer	243	216	218	257	270
Average price ($/CCF) per residential customer	$ 3.80	$ 3.54	$ 3.38	$ 2.98	$ 2.77
Debt service coverage ratio (DSC)[4, 5, 6, 7, 8, 9]	2.51	1.90	1.95	2.23	2.25
Employees[10]	165	165	165	164	165

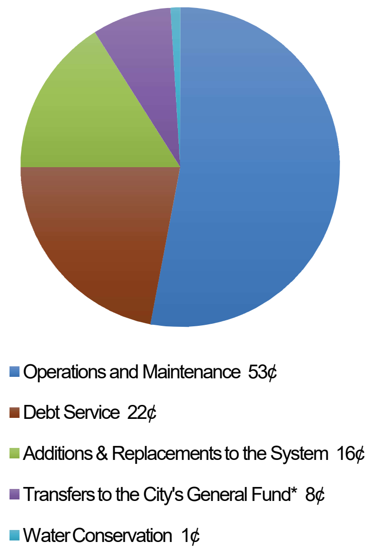
[1] Water pumping figures have been adjusted to include retail and wholesale potable water production. Excludes wheeling.
[2] No purchased water.
[3] System peak day has been adjusted to reflect production for retail customers.
[4] Interest expense used to calculate DSC is net of federal subsidy on Build America Bonds.
[5] Excludes GASB 68 *Accounting and Financial Reporting for Pension* non-cash adjustments of $3,107, $2,483, $(471), $(4,891), and $(1,107) for fiscal years 2024/25 through 2020/21, respectively.
[6] Excludes GASB 75 *Accounting and Financial Reporting for Postemployment Benefits Other Than Pensions* non-cash adjustments of $203, $173, $168, $210, and $73 for fiscal years 2024/25 through 2020/21, respectively.
[7] Includes GASB 87 *Leases* net revenue adjustments of $3,049, $3,023, $2,957, and $708 for fiscal years 2024/25 through 2021/22, respectively.
[8] Changes in fiscal year 2022/23 reflect reclassifications of certain long-term obligations and related accounts in connection with GASB 87 *Leases*.
[9] As restated for fiscal year ended June 30, 2024.
[10] Approved positions.

2024/2025 WATER REVENUE AND RESOURCES

SOURCE OF REVENUE

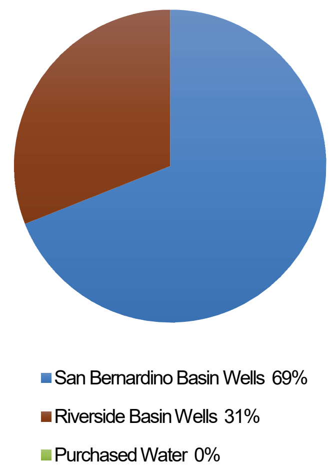


DISTRIBUTION OF REVENUE

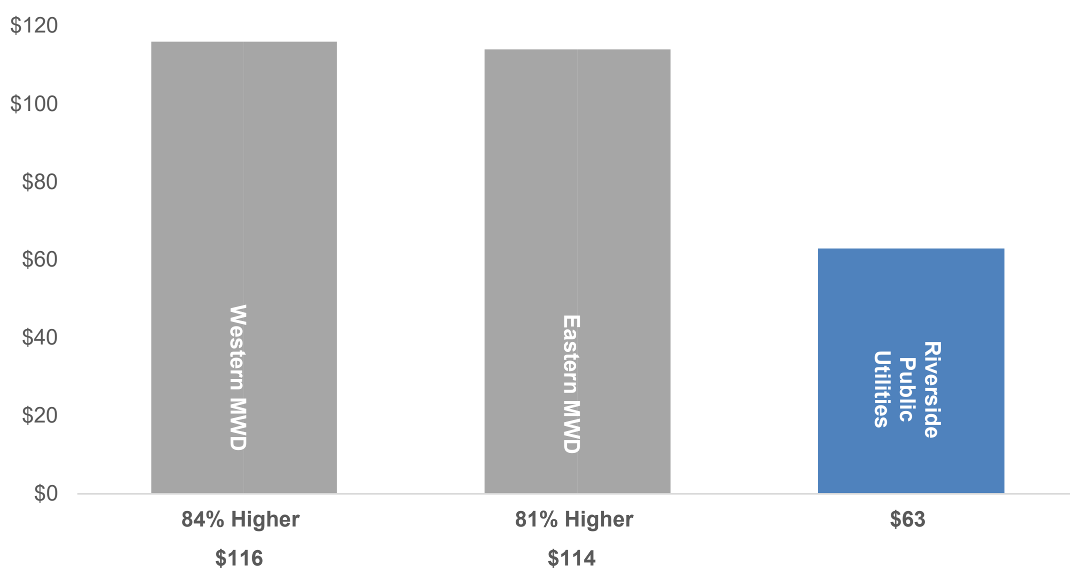


*Based on transfer of 11.5% of fiscal year 2023/2024 gross operating revenues, including adjustments.

WATER RESOURCES



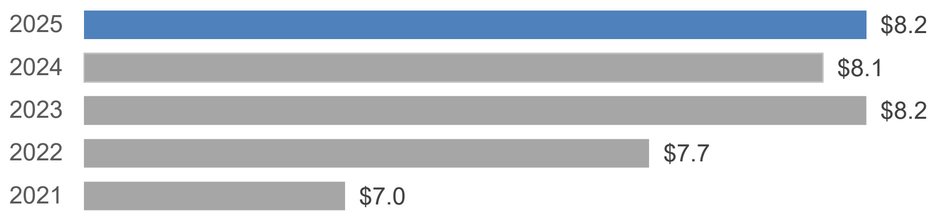
RESIDENTIAL WATER RATE COMPARISON - 20 CCF PER MONTH (AS OF JUNE 30, 2025)



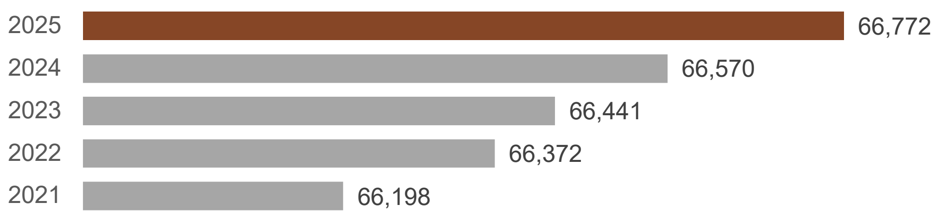
WATER ENERGY LIFE
CITY OF RIVERSIDE
PUBLIC UTILITIES

WATER KEY OPERATING INDICATORS

General Fund Transfer (In Millions)

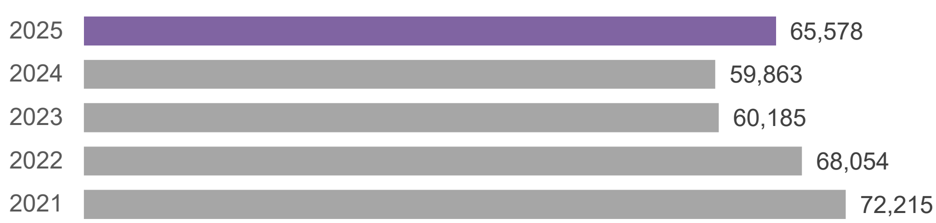


Number of Meters At Year-End

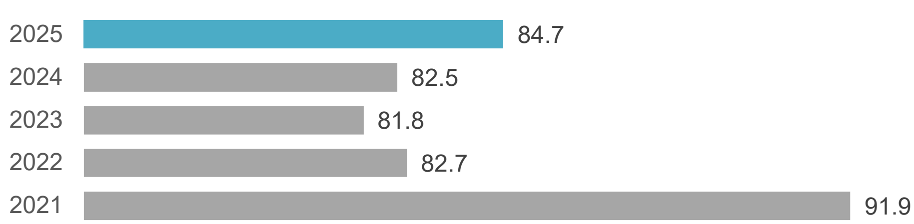


Total Operating Revenue (In Millions)

Potable Water Production (In Acre Feet)



Peak Day Demand (In Millions of Gallons)



WATER FACTS AND SYSTEM DATA

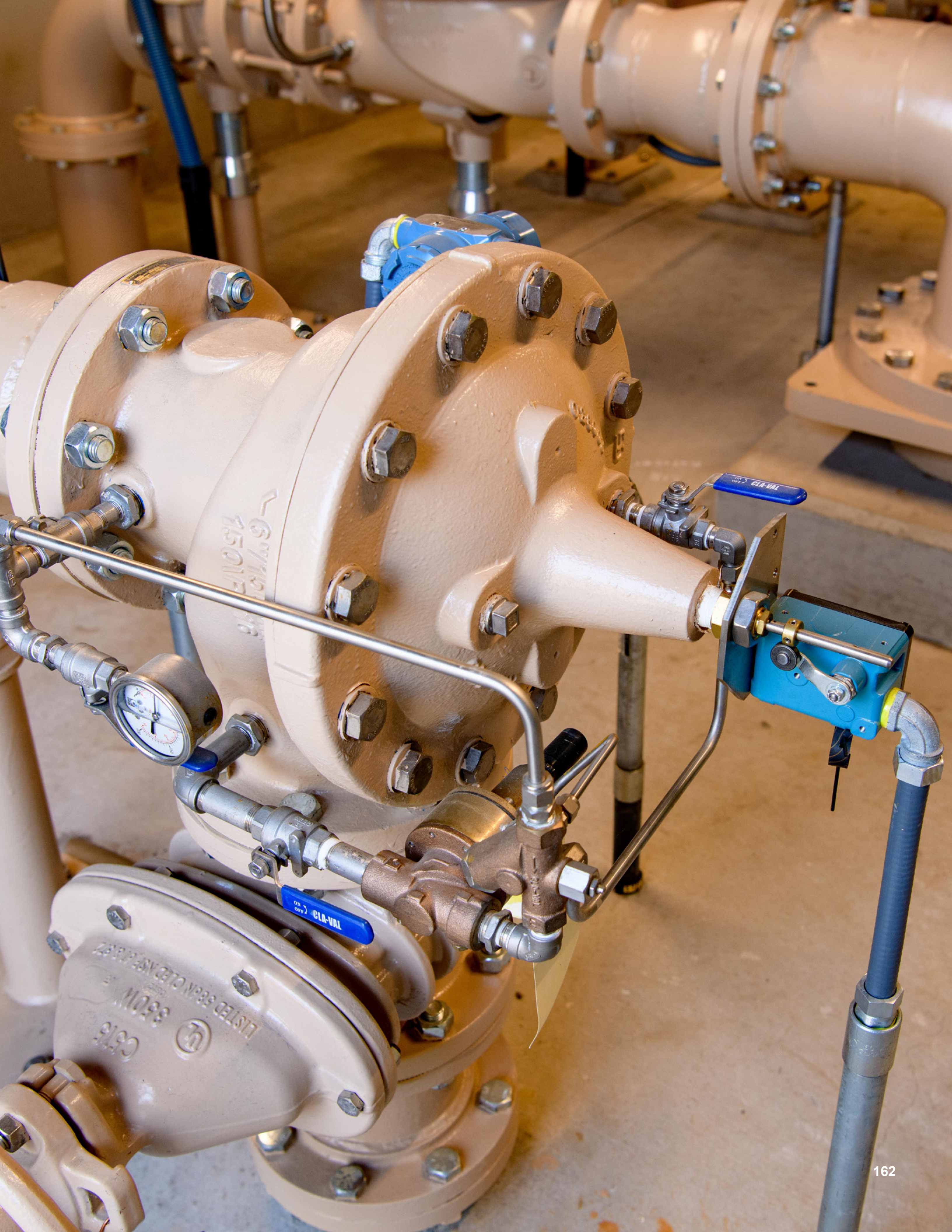
Established	1913
Service Area Population	320,278
Service Area Size (square miles)	74.24

System Data:

Smallest Pipeline	2.0"
Largest Pipeline	72.0"
Miles of Pipeline	998
Number of Domestic Wells	51
Number of Active Reservoirs	16
Total Reservoir Capacity (gallons)	108,500,000
Number of Treatment Plants	6
Number of Treatment Vessels	77
Miles of Canal	14
Number of Fire Hydrants	7,913
Daily Average Production (gallons)	61,500,000
2024-2025 Peak Day (gallons) 07/01/24, 94 degrees	84,700,000
Historical Peak (gallons) 08/09/05, 99 degrees	118,800,000

Bond Ratings:

Fitch Ratings	AA+
Moody's	Aa2
S&P Global Ratings	AA+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