2018
FINANCIAL REPORT

RIVERSIDE PUBLIC UTILITIES

RiversidePublicUtilities.com

WATER | ENERGY | LIFE

CITY OF RIVERSIDE

PUBLIC UTILITIES

OVERVIEW

Riverside Public Utilities generates, transmits and distributes electricity to a 90-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

325,801

RECORD PEAK DEMAND

Energy: 640 megawatts
8/31/2017

Water: 118,782,000 million gallons
8/9/2005

TOTAL OPERATING REVENUE

Energy: $363.8 million

Water: $66.7 million

CUSTOMERS

Energy: 109,619

Water: 68,640

CREDIT RATING

Energy:	AA-	Fitch
	AA-	Standard & Poors
Water:	AA+	Fitch
	AAA	Standard & Poors
	Aa2	Moody's

WATER | ENERGY | LIFE

CITY OF RIVERSIDE

PUBLIC UTILITIES

RiversidePublicUtilities.com

Cover artwork by
Jasmine Zamara, Norte Vista High School

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 **TEN-YEAR 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.

OUR
THREE-YEAR GOALS

1. Contribute to the City of Riverside’s economic development while preserving RPU’s financial strength.
2. Maximize the use of technology to improve utility operations.
3. Impact positive legislation and regulations at all levels of government.
4. Develop and implement electric and water resource plans.
5. Create and implement a workforce development plan.

OUR
TEN-YEAR GOALS

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

RiversidePublicUtilities.com

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CITY OF RIVERSIDE
PUBLIC UTILITIES

CITY COUNCIL

Rusty Bailey
Mayor

Mike Gardner
Ward 1

Andy Melendrez
Ward 2

Mike Soubirous
Ward 3

Chuck Conder
Ward 4

Chris Mac Arthur
Ward 5

Jim Perry
Ward 6

Steve Adams
Ward 7

BOARD OF PUBLIC UTILITIES

Jo Lynne Russo-Pereyra (Board Chair)
Citywide / Ward 4

David Crohn
Citywide / Ward 1

Jennifer O'Farrell
Ward 1

Kevin Foust
Ward 2

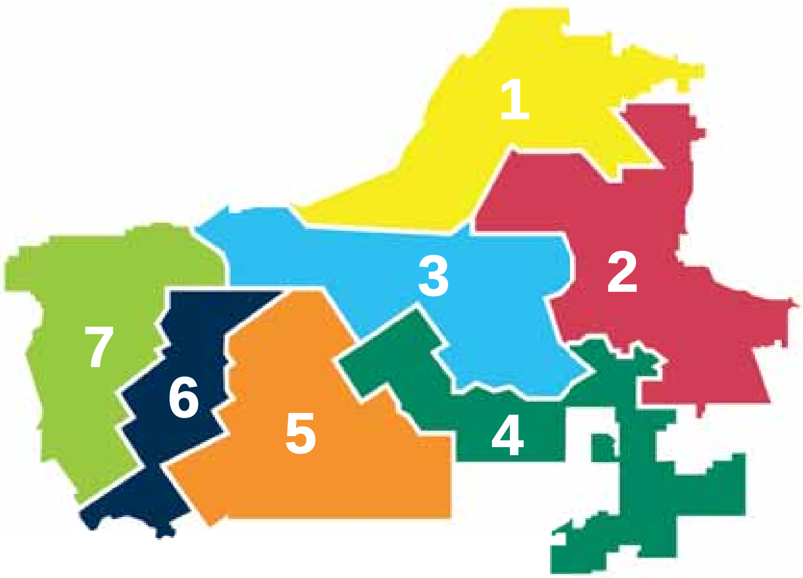
Elizabeth Sanchez-Monville
Ward 3

David Austin (Board Vice-Chair)
Ward 4

Andrew Walcker
Ward 5

Jeanette Hernandez
Ward 6

Gil Oceguera
Ward 7



EXECUTIVE MANAGEMENT

Al Zelinka
City Manager

Todd Jorgenson
Interim
Utilities General Manager

Laura M. Chavez-Nomura
Assistant General Manager
Finance/Administration

Daniel E. Garcia
Assistant General Manager
Resources

George Hanson
Assistant General Manager
Energy Delivery

Michael Plinski
Interim
Assistant General Manager
Water

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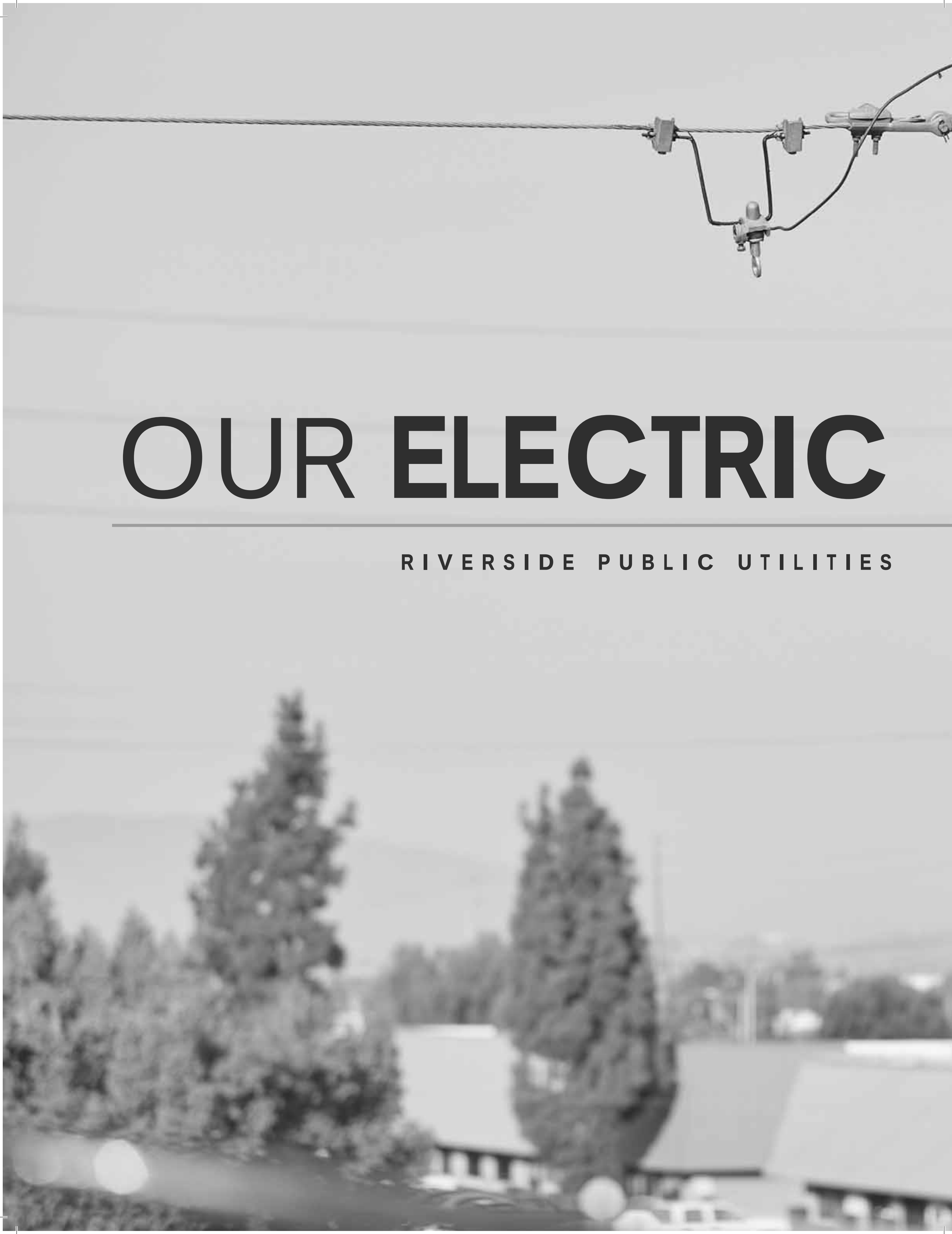
OUR **ELECTRIC**

RIVERSIDE PUBLIC UTILITIES




HIGH

Certified Public Accountants

Independent Auditor's Report

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

We have audited the accompanying financial statements of the Electric Utility Enterprise Fund (Electric Utility) of the City of Riverside, California, (the City), as of and for the years ended June 30, 2018 and 2017, and the related notes to the financial statements, as listed in the table of contents.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with accounting principles generally accepted in the United States of America; this includes 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.

Auditor's Responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements 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 entity's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Electric Utility of the City, as of June 30, 2018 and 2017, and the changes in financial position and cash flows thereof for the years then ended in accordance with accounting principles generally accepted in the United States of America.

Emphasis of 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 as of June 30, 2018 and 2017, the changes in its financial position, or, where applicable, its cash flows for the years 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.

Macias Gini & O'Connell LLP
4675 MacArthur Court, Suite 600
Newport Beach, CA 92660

www.mgocpa.com

Other Matters

Required Supplementary Information

Accounting principles generally accepted in the United States of America require that the management's discussion and analysis, as listed in the table of contents, be presented to supplement the financial statements. Such information, although not a part of the financial statements, is required by the Governmental Accounting Standards Board who considers it to be an essential part of financial reporting for placing the financial statements in an appropriate operational, economic, or historical context. We have applied certain limited procedures to the required supplementary information in accordance with auditing standards generally accepted in the United States of America, which consisted of inquiries of management about the methods of preparing the information and comparing the information for consistency with management's responses to our inquiries, the financial statements, and other knowledge we obtained during our audit of the financial statements. We do not express an opinion or provide any assurance on the information because the limited procedures do not provide us with sufficient evidence to express an opinion or provide any assurance.

Other Information

Our audit was conducted for the purpose of forming an opinion on the financial statements as a whole. The accompanying supplementary Electric Utility information is presented for the purposes of additional analysis and are not a required part of the financial statements. Such information has not been subjected to the auditing procedures applied in the audit of the financial statements, and accordingly, we do not express an opinion or provide any assurance on it.

Macias Gini & O'Connell LLP

Newport Beach, California
October 31, 2018

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 2017-18 financial report for the periods ended June 30, 2018 and 2017 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 31 of this report. All amounts, unless otherwise indicated, are expressed in thousands of dollars.

FINANCIAL HIGHLIGHTS

- During the fiscal year ended June 30, 2018, the Electric Utility implemented Governmental Accounting Standards Board Statement No. 75 (GASB 75), *Accounting and Financial Reporting for Postemployment Benefits Other Than Pensions* – a replacement of GASB Statements No. 45 as amended, and No. 57, and establishes new accounting and financial reporting requirements for Other Post-Employment Benefits (OPEB) plans. As of July 1, 2017, the Electric Utility restated beginning net position in the amount of $328 to record adjustments to the OPEB liability. For more information, refer to the OPEB section below, Note 6 of the accompanying financial statements. The Electric Utility did not restate the financial statements for the fiscal years ended June 30, 2017 and 2016 because the necessary actuarial information was not provided for the prior years presented.

- 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 $9,056 and ($248) in June 30, 2018 and 2017, respectively.

- Retail sales, net of uncollectibles/recovery were $305,969 and $308,781 for years ended June 30, 2018 and 2017, respectively. The decrease in sales was primarily due to reduced consumption.

- Utility plant assets as of June 30, 2018 increased by $12,462 primarily due to the completion of significant capital projects such as substation improvements, neighborhood street light retrofit, and major 4-12 kV conversions, as well as donated easements received for access to electrical systems, offset by current year depreciation.

- Total net position as of June 30, 2018 increased by $21,211 primarily due to positive operating results, and non-cash capital contributions for donated assets received.

- The Electric Utility used unrestricted reserves, set aside with monies received from settlements and cost recoveries associated with the early closure of the SONGS Units 2 and 3, for a partial bond defeasance of $11,005. The defeasance reduced debt outstanding and will realize interest savings of $10,233 over the remaining life of the bonds.

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 "Comprehensive Annual Financial Report."

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.

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 31 to 65 of this report.

ELECTRIC UTILITY FINANCIAL ANALYSIS

CONDENSED STATEMENTS OF NET POSITION

	2018	2017	2016
Current and other assets	$ 450,808	$ 464,254	$ 460,113
Capital assets	781,254	768,792	754,694
Deferred outflows of resources	50,285	65,176	64,735
Total assets and deferred outflows of resources	1,282,347	1,298,222	1,279,542
Long-term debt outstanding	529,294	557,540	571,100
Other liabilities	240,949	238,796	238,624
Deferred inflows of resources	6,692	17,685	24,204
Total liabilities and deferred inflows of resources	776,935	814,021	833,928
Net investment in capital assets	267,230	229,432	201,651
Restricted	48,906	47,727	40,913
Unrestricted	189,276	207,042	203,050
Total net position	$ 505,412 (1)	$ 484,201	$ 445,614

(1) Restated July 1, 2017, see Note 12 of the Financial Statements.

ASSETS AND DEFERRED OUTFLOWS OF RESOURCES

2018 compared to 2017 The Electric Utility's total assets and deferred outflows of resources were $1,282,347, reflecting an decrease of $15,875 (1.2%), primarily due to the following:

- Current and other assets, comprised of restricted and unrestricted assets, had a net decrease of $13,446, primarily due to a decrease in restricted assets of $12,714, which was primarily due to a decrease of $13,894 in cash and investments at fiscal agent for payment of decommissioning costs related to San Onofre Nuclear Generating Station (SONGS) Units 2 and 3. This decrease was offset by a slight increase in cash and cash equivalents related to proceeds on the sale of greenhouse gas (GHG) allowances.

- Capital assets increased by $12,462 primarily due to the receipt of $13,637 in donated land rights and easements for general access to electrical system assets, as well as additions and improvements to the Electric distribution infrastructure system to improve service and reliability to Electric Utility's customers. This increase was offset by current year depreciation. Additional capital asset information can be found in the "Capital Assets and Debt Administration" section.

- Deferred outflows of resources decreased by $14,891 primarily due to pension related adjustments which included the changes in assumptions and the change in projected versus actual earnings on pension plan investments as determined by the plan actuary. In addition, there was a decrease in the negative fair market value of interest rate swaps. Additional information can be found in the "Interest Rate Swaps on Revenue Bonds" section of Note 4 Long-term Obligation.

2017 compared to 2016 Total assets and deferred outflows of resources were $1,298,222, a net increase of $18,680 (1.5%). Current and other assets had a net increase of $4,141 primarily due to an increase of $6,249 in cash and cash equivalents due to positive operating results and settlement recoveries received and an increase of $1,591 in unamortized purchased power for the prepayment of power supply costs related to the Salton Sea power purchase agreement. This was offset by a decrease of $4,136 in restricted assets, due to a decrease of $9,452 in cash and investments at fiscal agent for payment of decommissioning costs related to San Onofre Nuclear Generating Station (SONGS) Units 2 and 3 and an increase of $5,542 related to the sale of renewable energy credits and regulatory transactions. Capital assets increased by $14,098 primarily due to the receipt of $16,011 in donated land rights and easements for general access to electrical system assets, capital projects for additions and improvements to the Electric distribution infrastructure system and technology upgrades used to improve service to the Electric Utility's customers.

LIABILITIES AND DEFERRED INFLOWS OF RESOURCES

2018 compared to 2017 The Electric Utility's total liabilities and deferred inflows of resources were $776,935, a decrease of $37,086 (4.6%), due to the following:

- Long-term debt outstanding decreased by $28,246 primarily due to the principal payments on revenue bonds and the amortization of bond premiums, along with a bond defeasance of $11,005. Additional debt information can be found in the "Capital Assets and Debt Administration" section.

- Other liabilities increased by $2,153 primarily due to an increase of $12,693 in net pension liability and an increase of $769 in accounts payable and other accruals, offset by a decrease of $7,297 in the negative fair value of derivative instruments, and a decrease of $4,097 in nuclear decommissioning liabilities.

- Deferred inflows of resources decreased by $10,993 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.

2017 compared to 2016 Total liabilities and deferred inflows of resources were $814,021, a decrease of $19,907 (2.4%). Long-term debt outstanding decreased by $13,560 primarily due to the principal payments on revenue bonds and the amortization of bond premiums. Deferred inflows of resources decreased by $6,519 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

2018 compared to 2017 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 $505,412, an increase of $21,211 (4.4%) which is primarily attributed to positive operating results, non-cash capital contributions for donated assets received, and settlement recoveries. The following represents the changes in components of Net Position:

- The largest portion of the Electric Utility's total net position, $267,230 (52.9%), reflects its investment in capital assets less any related outstanding debt used to acquire those assets. This portion increased by $37,798 primarily due to an increase in capital assets constructed or purchased during the year, net of related debt, and donated capital assets received. Additional capital asset information can be found in the "Capital Assets and Debt Administration" section.

- The restricted portion of net position totaled $48,906 (9.7%), an increase of $1,179, 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 $189,276 (37.4%) an decrease of $17,766 from prior year, primarily attributable to the payment on bond defeasance and the use of unrestricted cash and cash equivalent to fund capital projects. Unrestricted net position may be used to meet the Electric Utility's ongoing operational needs and obligations to customers and creditors.

2017 compared to 2016 Total net position, increased by $38,587 (8.7%), to a total of $484,201. Net investment in capital assets increased by $27,781 primarily due to an increase in capital assets constructed or purchased during the year, net of related debt, and donated capital assets received. Restricted net position increased by $6,814 and the unrestricted portion increased by $3,992 primarily due to positive operating results and settlement recoveries received.

ELECTRIC UTILITY FINANCIAL ANALYSIS (CONTINUED)

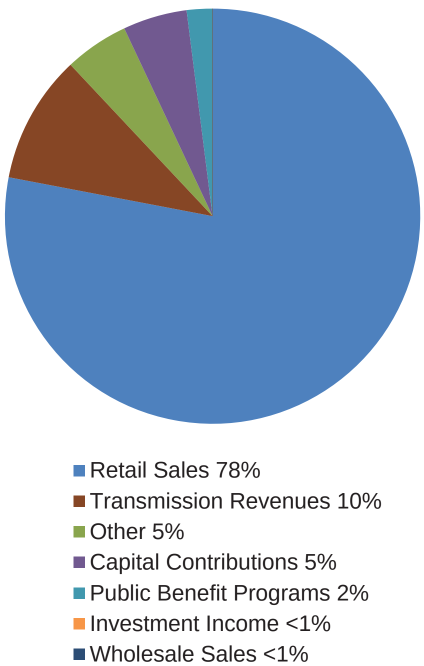
CONDENSED STATEMENTS OF CHANGES IN NET POSITION

	2018	2017	2016
Revenues:			
Retail sales, net	$ 305,969	$ 308,781	$ 304,486
Wholesale sales	2	9	3
Transmission revenues	37,484	35,497	32,924
Investment income	2,567	1,809	5,143
Other revenues	18,922	20,493	26,040
Public Benefit Programs	8,860	8,880	8,929
Capital contributions	20,182	19,684	14,874
Total revenues	393,986	395,153	392,399
Expenses:			
Production and purchased power	136,423	132,349	137,081
Transmission	62,981	59,497	58,145
Distribution	67,436	59,906	49,346
Public Benefit Programs	7,820	7,602	6,657
Depreciation	33,585	32,642	30,953
Interest expenses and fiscal charges	24,129	25,340	24,980
Total expenses	332,374	317,336	307,162
Transfers to the City's general fund	(40,073)	(39,230)	(38,360)
Changes in net position	21,539	38,587	46,877
Net position, July 1, as previously reported	484,201	445,614	398,737
Less: Cumulative effect of change in accounting principle (1)	(328)	-	-
Net position, July 1, as restated	483,873	445,614	398,737
Net position, June 30	$ 505,412	$ 484,201	$ 445,614

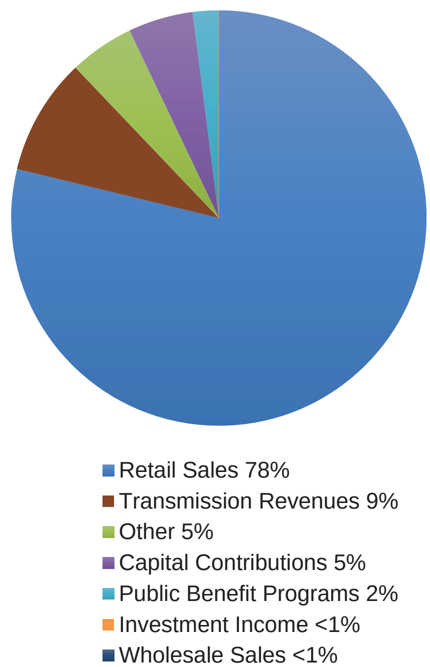
(1) For the implementation of postemployment benefits other than pensions, GASB Statement No. 75.

REVENUES BY SOURCES

June 30, 2018



June 30, 2017



2018 compared to 2017 The Electric Utility's total revenues of $393,986 decreased by $1,167 (0.3%) with changes in the following:

- Retail sales (residential, commercial, industrial, and others), net of uncollectibles/recovery, totaled $305,969, a $2,812 (0.9%) decrease. Retail sales continue to be the primary revenue source for the Electric Utility. The decrease in sales was primarily due a slight decrease in consumption.

- Transmission revenues of $37,484 increased by $1,987 (5.6%), primarily due to an increase in the high voltage utility specific rate per the annual filing with Federal Energy Regulatory Commission.

- Other revenues of $18,922 decreased by $1,571 (7.7%), primarily due to a decrease in proceeds from the sale of renewable energy credits and settlement recoveries, offset by an increase of proceeds on the sale of GHG allowances.

2017 compared to 2016 The Electric Utility's total revenues of $395,153 increased by $2,754 (0.7%) with changes in the following:

- Retail sales (residential, commercial, industrial, and others), net of uncollectibles/recovery, totaled $308,781, a $4,295 (1.4%) increase. The increase in sales was primarily due to a slight increase in customer consumption as a result of warmer weather during the summer season.

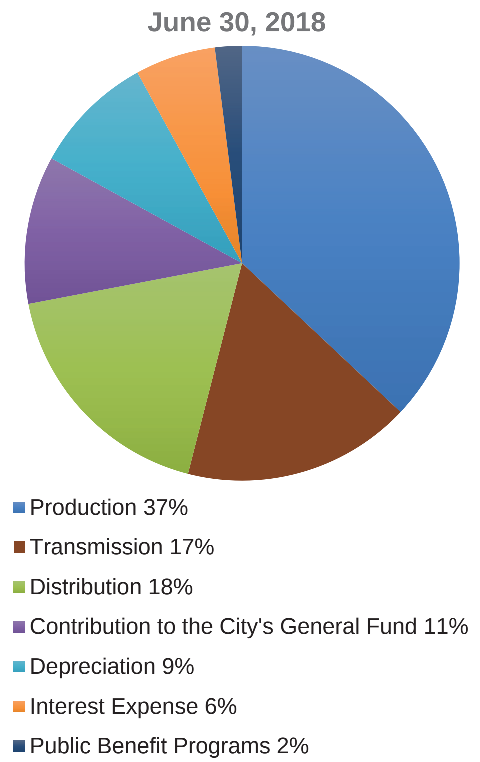
- Transmission revenues of $35,497 increased by $2,573 (7.8%), primarily due to an increase in the high voltage utility specific rate per the annual filing with Federal Energy Regulatory Commission.

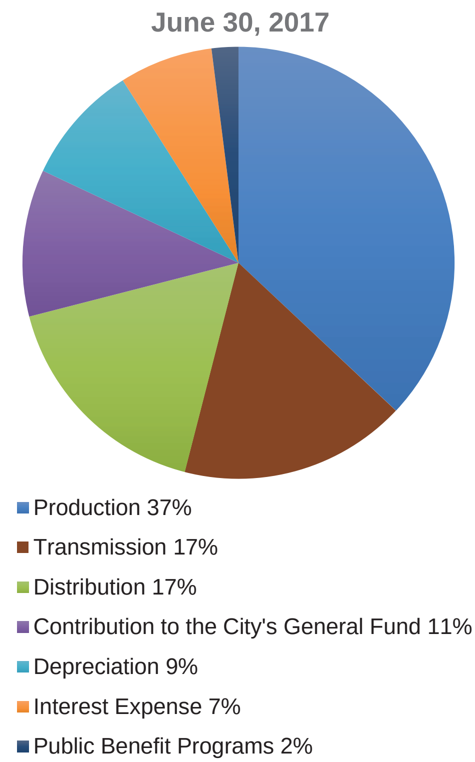
ELECTRIC UTILITY FINANCIAL ANALYSIS (CONTINUED)

- Other revenues of $20,493 decreased by $5,547 (21.3%), primarily due to a decrease of $10,820 in settlement recoveries as compared to prior year, offset by an increase of $5,021 in proceeds from the sale of renewable energy credits and regulatory transactions.

- Capital contributions of $19,684 increased by $4,810 (32.3%), due to an increase in donated land rights and easements for general access to electrical system assets.

EXPENSES BY SOURCES





2018 compared to 2017 The Electric Utility's total expenses, excluding general fund transfer, were $332,374, an increase of $15,038 (4.7%). The increase was primarily due to the following:

- Production and purchased power expenses of $136,423 increased by $4,074 (3.1%) primarily due to an increase in power supply costs in the current year and new renewable energy projects coming online.

- Transmission expenses of $62,981 increased by $3,484 (5.9%), mainly due to increases in the transmission access charge from the California Independent System Operator (CAISO).

- Distribution expenses of $67,436 increased by $7,530 (12.6%), mainly due to non-cash pension expense adjustment of $9,056 as a result of pension accounting standards, as well as an overall increase in general operating expenses. This is offset by a decrease of a one-time expenditure in the prior year of $2,593 in pension obligation.

- Depreciation expense of $33,585 increased by $943 (2.9%), reflecting the completion of capital projects and their current year depreciation.

2017 compared to 2016 Total expenses, excluding general fund transfer, were $317,336, an increase of $10,174 (3.3%). The increase was primarily due to the following:

- Production and purchased power expenses of $132,349 decreased by $4,732 (3.5%) primarily due to the prior year recognition of SONGS replacement power of $7,160 associated with the shutdown of Units 2 and 3 as an expense, partially offset by an increase in power supply costs in the current year for the increase in customer consumption and new renewable energy projects coming online.

- Transmission expenses of $59,497 increased by $1,352 (2.3%), mainly due to increases in the transmission access charge from the California Independent System Operator (CAISO).

- Distribution expenses of $59,906 increased by $10,560 (21.4%), mainly due to a prior year non-cash pension expense credit of $5,036 as a result of pension accounting standards, the City's refinancing of pension obligation bonds resulting in an additional obligation of $2,593 to the Electric Utility for its share of the bonds, and an increase of general operating expenses.

- Depreciation expense of $32,642 increased by $1,689 (5.5%), reflecting the completion of capital projects and their current year depreciation.

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 $40,073 and $39,230 for 2018 and 2017, respectively based on the gross operating revenue provisions in the City's Charter.

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:

	2018	2017	2016
Production	$ 178,597	$ 187,543	$ 196,489
Transmission	26,237	27,068	27,425
Distribution	375,143	363,986	361,948
General	68,674	72,923	74,282
Intangibles	15,366	17,140	17,134
Land	52,111	37,845	21,439
Intangibles, non-amortizable	10,651	10,651	10,651
Construction in progress	54,475	51,636	45,326
Total capital assets	$ 781,254	$ 768,792	$ 754,694

CAPITAL ASSETS AND DEBT ADMINISTRATION (CONTINUED)

2018 compared to 2017 The Electric Utility's investment in capital assets, net of accumulated depreciation, was $781,254, an increase of $12,462 (1.6%). The increase resulted primarily from the following significant capital projects offset by current year depreciation:

- $22,474 in additions and improvements to the Electric system, such as substations, transformers, underground conduit and conductors, neighborhood streetlights, and distribution line extensions and replacements to serve customers.
- $13,637 in donated land rights and easements for general access to electrical system assets.
- $2,197 in upgrades of lower voltage (4kV) electric distribution facilities to higher distribution voltage (12kV) to reduce system losses, increase capacity for necessary system growth, and improve system reliability.
- $3,207 for the Riverside Transmission Reliability Project for additional generation import capability for a second point of interconnection with the State's high voltage transmission grid.

2017 compared to 2016 Investment in capital assets, net of accumulated depreciation, was $768,792, an increase of $14,098 (1.9%). The increase resulted from $19,963 in additions and improvements to the Electric system, $16,011 in donated land rights and easements for general access to electrical system assets, $3,277 in upgrades of lower voltage (4kV) electric distribution facilities to higher distribution voltage (12kV), and $2,601 for the Riverside Transmission Reliability Project for additional generation import capability for a second point of interconnection with the State's high voltage transmission grid.

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:

	2018	2017	2016
Revenue bonds	$ 528,715	$ 553,515	$ 566,835
Unamortized premium	6,624	7,402	8,213
Pension obligation bonds	10,418	12,312	10,084
Less: Current portion of revenue and pension obligation bonds	(16,463)	(15,689)	(14,032)
Total	$ 529,294	$ 557,540	$ 571,100

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 2.71, 2.95, and 2.87 at June 30, 2018, 2017 and 2016, respectively. This debt is backed by the revenues of the Electric Utility. The prior years' debt service coverage ratio has been restated to exclude the non-cash pension related adjustment for required pension accounting standards. For additional information, see Note 4 of the accompanying financial statements and Key Historical Operating Data section.

2018 compared to 2017 The Electric Utility's long-term debt decreased by $28,246 (5.1%) to $529,294 as a result of principal payments and amortization of bond premiums, along with the principal payment for bond defeasance.

2017 compared to 2016 Long-term debt decreased by $13,560 (2.4%) to $557,540 primarily due to principal payments and amortization of bond premiums, offset by the increase in the proportionate share of the pension obligation bonds.

CAPITAL ASSETS AND DEBT ADMINISTRATION (CONTINUED)

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

CREDIT RATINGS

The Electric Utility maintains a credit rating of "AA-" from both Standard & Poor's (S&P) and Fitch Ratings (Fitch).

In November 2016, S&P affirmed its "AA-" rating on the Electric Utility's revenue bonds. The rating reflects the Electric Utility's strong debt service coverage, strong liquidity position and the Electric Utility's diverse and low-cost resource portfolio, including an emphasis on renewal energy resources.

In June 2017, Fitch also affirmed its "AA-" rating on the Electric Utility's revenue bonds. This rating is a result of the Electric Utility's evolving power resource portfolio which is well positioned to meet California's increasing environmental regulations, stable financial performance and strong liquidity levels.

The Electric Utility has maintained these credit ratings since 2008.

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 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. Thereafter, the utilities are likely to be required to purchase allowances 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 in 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.

SENATE BILL (SB) 1 – CALIFORNIA SOLAR INITIATIVE

SB 1, enacted in 2006, requires municipal utilities to establish a program supporting the stated goal of the legislation to install 3,000 megawatts (MW) of photovoltaic (PV) resources in California. Municipal utilities are also required to establish eligibility criteria in collaboration with the California Energy Commission (CEC) for funding solar energy systems receiving ratepayer funded incentives and meet reporting requirements regarding the installed capacity, number of installed systems, number of applicants, and awarded incentives. The SB1 program officially sunset in December 2016 and closed in RPU service territory in December 2017. As of program close, Electric Utility customers have installed approximately 14.17 MW of solar PV capacity in conjunction with the SB 1 program. To date, Electric Utility customers have installed approximately 24.42 MW of solar PV capacity throughout the city, either independently or in conjunction with the SB 1 program.

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 lbs/megawatt hour (MWh). SB 1368 essentially prohibits any long-term investments in generating resources based on coal. Thus, SB 1368 disproportionally impacts Southern California POU's as these utilities have heavily invested in coal technology.

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. POU's were required to submit compliance reports to the CEC of their first adopted target by January 1, 2017. The utility's second adopted target compliance report is due to the CEC by January 1, 2021.

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 energy storage procurement targets. The City finished its investigation of energy storage pricing and benefits in September 2014 and adopted a zero megawatts 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 must reevaluate its assessment not less than every three years or 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, improve energy efficiency, and demonstrate the City's proactive support of the State's energy storage goals. 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 26, 2017, after reevaluating its assessment of the first adopted energy storage procurement target of zero megawatts, the City 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 study area was initiated to review the summer and winter assessment that 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 earlier of 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, or March 31, 2017. Aliso Canyon has not been able to meet its injection and withdrawal targets, therefore, these tighter OFO tariff restrictions will continue 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 July 19, 2017, DOGGR issued a press release on their determination, in concurrence with the CPUC, that Aliso Canyon is 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. Withdrawals from Aliso Canyon can be made during emergency conditions to avoid electric load shed and/or gas curtailments to customers.

The Electric Utility fulfilled its system reliability without any issues during multiple heat waves in both 2016 and 2017. Going forward, the Electric Utility will continue to monitor workshops and new legislation and regulations that impact the status of Aliso Canyon and its effect on the reliability of our service territory. Senate Bill 380 added Section 715 to the Public Utilities Code, which requires the CPUC to determine the range of Aliso inventory necessary to ensure safety, reliability, and just and reasonable rates. In the most recent 715 Report, the Energy Division recommended that the maximum allowable Aliso inventory be increased from 24.6 to 34 billion cubic feet for summer 2018 due to continuing pipeline outages on the SoCalGas system. As of July 20, 2018, the results of the 114 injection well tests are as follows: 59 wells have completed all required tests and of those 57 wells have received final DOGGR approval; 25 wells are currently in the second phase of inspections; 29 wells are in the process of abandonment; and 3 wells have been plugged and abandoned.

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 publically owned utilities serving more than 100,000 customers. These utilities, including IOUs, 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.

The Electric Utility is still waiting upon direction from the CEC on the actual MW obligation shares and the target date on when the contracts must be procured. It is expected that these facilities will be counted towards the Electric Utility's Renewable Portfolio Standard (RPS) goals and preliminary analysis indicates that the City's MW share should be minimal. 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.

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. The remaining MW procurement requirement is currently undergoing negotiations with another entity.

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 a) the increased mandate of the California RPS to 50% by December 31, 2030, b) doubling of energy efficiency savings by January 1, 2030, and c) providing for the transformation of the CAISO into a regional organization. In addition, there is a specific Integrated Resource Planning (IRP) mandate embedded in the bill that applies to 16 POUs that have a 3-year average annual demand over 700 GWh, which includes the Electric Utility.

The Electric Utility's current IRP was completed in 2014 and approved by the Board of Public Utilities and City Council in 2015 and will continue to be approved in this manner going forward. The current IRP addresses most of the required topics to some extent, but will require further study and expansion on certain topics.

By January 1, 2019, the governing board of the Electric Utility expects to adopt an IRP and a process for updating the plan every 5 years. The IRP must address specific topics such as energy efficiency and demand response resources, transportation electrification, GHG emissions, energy storage resources, enhance 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.

Shortly thereafter, 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. 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- GREENHOUSE GAS EMISSIONS INTENSITY REPORTING

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 2020 for calendar year 2019 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. Per this requirement, Riverside reinstated the inclusion of printed disclosures of the PCL with its September 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, but is still in the pre-rulemaking process. 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 are required and have yet to be scheduled. Once the CEC officially begins the rulemaking process, then they must finalize and adopt the updated regulations for it to be effective in 2020. Riverside continues to monitor the workshops and draft regulations for any impacts to the utility's reporting and resources in meeting this requirement.

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. AB 398 required the CARB to update their scoping plan no later than January 1, 2018 and that all GHG rules and regulations that are adopted are consistent with this plan. On July 27, 2017, the ARB approved the 2016 Cap-and-Trade Amendments, which includes the Electric Utility's 2021-2030 allowance allocations they will receive each year. The Electric Utility's allowance allocations should be more than sufficient to cover all of our 2021-2030 direct compliance obligations.

Initially, it was unclear under AB 398 whether the Electric Utility would be required to consign 100% of their allowances to the market and then purchase allowances to fulfill its compliance obligations. POUs receive a sufficient amount of allowances each year to cover their compliance. Since the start of the Cap and Trade program in 2012, POUs have been able to use those received allowances for compliance. However, in

2017, the CARB announced they were reconsidering that provision. In early 2018, after much discussion and collaboration with the CARB in which the POUs demonstrated that they are including the price of GHG emissions in cost of energy, it was agreed that the POUs would not be forced to consign their allocated allowances and the structure would remain the same as it has and currently functions. Other unknown components of the law are the banking provisions and the specific GHG revenue spending requirement for revenues generated from the sale of excess allowances. CARB will be hosting more workshops and issuing the next iteration of regulation changes in 2018 and 2019. 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 requires 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. 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 System is 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 must provide 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 annually with the first report due by June 1, 2018.

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

SB 100, signed into law on September 10, 2018, increases the RPS goals of SBX1-2 and one of the primary components of SB 350 by modifying the RPS percentage targets of certain compliance periods. It does not replace SB 350. The measure maintains the 33% RPS target by December 31, 2020, while the compliance periods following it changed to 44% by December 31, 2024, 52% by December 31, 2027, and 60% by December 31, 2030. SB 100 is also known as The 100 Percent Clean Energy Act of 2018 because the bill creates the policy of planning to meet all of the state's retail electricity supply with a mix of RPS-eligible and zero-carbon resources by December 31, 2045, for a total of 100 percent clean energy.

The CEC is required to establish appropriate multiyear compliance periods for all subsequent years after 2030 that will require POUs to procure not less than 60% of retail sales from renewable resources. It is expected that workshops, rulemakings, and updated regulations will be implemented soon by the CEC to incorporate the SB 100 mandate in the RPS Guidebook and RPS Enforcement Procedures for POUs. In addition, POUs will need to include the increased requirements in their future IRP. Riverside will continue to monitor the outcome and impacts of any upcoming workshops and regulations in meeting the new requirements.

FIVE-YEAR ELECTRIC RATE PLAN

On May 22, 2018, the City Council approved a five-year Electric Rate Plan, with rate increases that will become effective on January 1, 2019, 2020, 2021, 2022 and 2023 with annual reviews of the adopted rates by City Council. The system average rate increase effective January 1, 2019 is 2.95%, followed by system average rate increases of 3.0% in years two through five. The Electric Rate Plan includes the introduction of electric rate components over a five-year period to better align with its cost of serving customers and its revenue requirement. The Electric Rate Plan is designed to provide financial stability and correct the imbalance of costs versus revenue recovery by increasing fixed cost recovery through monthly service charges and a new network access charge to reflect the nature of underlying costs. Pursuant to City Council direction, the first annual review of rates will be conducted in December of 2019.

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. 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 most recent in 2012. In 2009, the City also adopted sustainability policies associated with economic development as part of the "Seizing Our Destiny" citywide vision, incorporating a "Becoming a Green Machine" strategic route with specific initiatives. 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).

In 2012, the City hosted the first of three community-wide Green Riverside Leadership Summits. Subsequent summits were held in 2014 and 2016, the former in partnership with the University of California Riverside and the latter as part of the community-led Riverside Green Festival and Summit.

ECONOMIC DEVELOPMENT AND GREEN INITIATIVES (CONTINUED)

In 2015, the City earned a 3-STAR Community Rating designation from Sustainability Tools for Assessing and Rating (STAR) Communities, an organization that works to evaluate, improve and certify sustainable communities. The City is now developing a submission package to earn a 4-STAR Community Rating.

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.

In 2017, the Electric Utility enjoyed additional load growth and new revenue associated with three large economic development projects in the City. These projects include Riverside Community Hospital's $360 million expansion for a seven story, 250,000 square foot patient tower with 120 new beds. Other projects include Sigma Plastics expansion with the addition of a new stretch film production line and a new customer to the Electric Utility, Garden Highway Foods with their new fresh fruit and vegetable processing facility. Combined these businesses resulted in over 6 MW of new electric load and new revenue of $3.1 million annually.

In 2017, the City received the "Outstanding Award" for Climate Change from the Association of Environmental Professional (AEP) for the Riverside Restorative Growthprint (RRG) Plan, a comprehensive plan adopted in 2016 with two major parts: an Economic Prosperity Action Plan and a Climate Action Plan. The Electric Utility played a key role in the City's effort to create and adopt RRG, which helps the City identify GHG reduction measures and strategies with the greatest potential to drive local economic development through clean-tech investment and the expansion of local green businesses. Ultimately, this effort spurs entrepreneurship and smart growth while advancing the City's GHG reduction 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. The City's Green Business Program recognizes local businesses for pursing sustainability in their facilities and operations. Businesses are evaluated based on their efforts to reduce pollution and waste and to improve resource use efficiency. Once certified through the program, the businesses are recognized locally and statewide through the California Green Business Network, a network of over 3,600 other businesses in the State of California that have already committed to pursuing greener practices. Currently, the City has certified UTC Aerospace, OSI Industries and the Riverside Convention Center with this designation.

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. These programs include, the Small Business Direct Installation Program, which has helped over 6,000 participants save over $2.0 million in utility costs and conserve over 13 million kilowatt hours (kWh).

The City initiated an ambitious LED streetlight replacement program in 2016. The program will eventually replace all city-owned streetlights by 2019, resulting in approximately 10 million kWh saved annually along with substantially reduced maintenance costs. The Electric Utility's grant program continues to provide assistance to local universities by providing funding for important research projects that explore new ways to advance energy technology and water conservation techniques.

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.

ECONOMIC DEVELOPMENT AND GREEN INITIATIVES (CONTINUED)

For more information on these economic development and green initiatives, go to GreenRiverside.com.

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 Assistant General Manager Finance/Administration, Riverside Public Utilities, 3750 University Avenue, 3rd floor, Riverside, CA 92501. Additional financial information can also be obtained by visiting www.RiversidePublicUtilities.com.

ELECTRIC UTILITY:
FINANCIAL STATEMENTS

STATEMENTS OF NET POSITION

ASSETS AND DEFERRED OUTFLOWS OF RESOURCES	June 30, 2018	June 30, 2017
	(in thousands)	
NON-CURRENT ASSETS:		
Utility plant:		
Utility plant, net of accumulated depreciation (Note 3)	$ 781,254	$ 768,792
Restricted assets:		
Cash and investments at fiscal agent (Note 2)	$ 69,047	82,941
Other non-current assets:		
Advances to other funds of the City	4,227	4,665
Unamortized purchased power (Note 10)	10,913	8,927
Regulatory assets	1,949	3,056
Total other non-current assets	17,089	16,648
Total non-current assets	867,390	868,381
CURRENT ASSETS:		
Unrestricted assets:		
Cash and cash equivalents (Note 2)	257,155	255,496
Accounts receivable, less allowance for doubtful accounts 2018 $629; 2017 $509	32,799	35,432
Advances to other funds of the City	305	183
Accrued interest receivable	1,016	891
Inventory	1,097	1,097
Prepaid expenses	22,842	23,382
Unamortized purchased power (Note 10)	218	124
Total unrestricted current assets	315,432	316,605
Restricted assets:		
Cash and cash equivalents (Note 2)	32,784	32,633
Public Benefit Programs - cash and cash equivalents (Note 2)	15,575	14,500
Public Benefit Programs receivable	881	927
Total restricted current assets	49,240	48,060
Total current assets	364,672	364,665
Total assets	1,232,062	1,233,046
DEFERRED OUTFLOWS OF RESOURCES:		
Deferred outflows related to pension (Note 5)	30,596	38,247
Changes in derivative values	10,692	17,157
Loss on refunding	8,997	9,772
Total deferred outflows of resources	50,285	65,176
Total assets and deferred outflows of resources	$ 1,282,347	$ 1,298,222

See accompanying notes to the financial statements

STATEMENTS OF NET POSITION

NET POSITION, LIABILITIES AND DEFERRED INFLOWS OF RESOURCES	June 30, 2018 (in thousands)	June 30, 2017
NET POSITION:		
Net investment in capital assets	$ 267,230	$ 229,432
Restricted for:		
Regulatory requirements (Note 7)	16,093	16,123
Debt service (Note 7)	16,691	16,510
Public Benefit Programs	16,122	15,094
Unrestricted	189,276	207,042
Total net position	505,412	484,201
LONG-TERM OBLIGATIONS, LESS CURRENT PORTION (NOTE 4)	529,294	557,540
OTHER NON-CURRENT LIABILITIES:		
Compensated absences (Note 4)	521	808
Net pension liability (Note 5)	108,886	96,193
Nuclear decommissioning liability (Note 9)	55,120	56,067
Net other postemployment benefits liability (Note 6)	8,283	7,905
Derivative instruments (Note 4)	15,228	22,525
Capital leases payable (Note 4)	2,274	3,098
Total non-current liabilities	190,312	186,596
CURRENT LIABILITIES PAYABLE FROM RESTRICTED ASSETS:		
Accrued interest payable	4,846	5,215
Public Benefit Programs payable	235	233
Nuclear decommissioning liability (Note 9)	5,457	8,607
Current portion of long-term obligations (Note 4)	16,463	15,689
Total current liabilities payable from restricted assets	27,001	29,744
CURRENT LIABILITIES:		
Accounts payable and other accruals	17,178	16,409
Customer deposits	6,397	5,996
Unearned revenue	61	51
Total current liabilities	23,636	22,456
Total liabilities	770,243	796,336
DEFERRED INFLOWS OF RESOURCES:		
Deferred inflows related to pension (Note 5)	6,396	17,685
Deferred inflows related to other postemployment benefits (Note 6)	296	-
Total deferred inflows of resources	6,692	17,685
Total net position, liabilities and deferred inflows of resources	$ 1,282,347	$ 1,298,222

See accompanying notes to the financial statements

STATEMENTS OF REVENUES, EXPENSES AND CHANGES IN NET POSITION

	For the Fiscal Years Ended June 30, 2018 (in thousands)	2017
OPERATING REVENUES:		
Residential sales	$ 115,630	$ 117,662
Commercial sales	71,128	71,456
Industrial sales	115,106	115,432
Other sales	4,792	4,782
Wholesale sales	2	9
Transmission revenue	37,484	35,497
Other operating revenue	11,514	12,899
Public Benefit Programs	8,860	8,880
Total operating revenues before uncollectibles	364,516	366,617
Estimated uncollectibles, net of bad debt recovery	(687)	(551)
Total operating revenues, net of uncollectibles	363,829	366,066
OPERATING EXPENSES:		
Production and purchased power	136,423	132,349
Transmission	62,981	59,497
Distribution	67,436	59,906
Public Benefit Programs	7,820	7,602
Depreciation	33,585	32,642
Total operating expenses	308,245	291,996
Operating income	55,584	74,070
NON-OPERATING REVENUES (EXPENSES):		
Investment income	2,567	1,809
Interest expense and fiscal charges	(24,129)	(25,340)
Gain on sale of assets	579	420
Other	6,829	7,174
Total non-operating revenues (expenses)	(14,154)	(15,937)
Income before capital contributions and transfers out	41,430	58,133
Capital contributions	20,182	19,684
Transfers out - contributions to the City's general fund	(40,073)	(39,230)
Total capital contributions and transfers out	(19,891)	(19,546)
Increase in net position	21,539	38,587
NET POSITION, BEGINNING OF YEAR, AS PREVIOUSLY REPORTED	484,201	445,614
LESS: CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE	(328)	-
NET POSITION, BEGINNING OF YEAR, AS RESTATED	483,873	445,614
NET POSITION, END OF YEAR	$ 505,412	$ 484,201

See accompanying notes to the financial statements

STATEMENTS OF CASH FLOWS

	For the Fiscal Years Ended June 30, 2018 (in thousands)	2017
CASH FLOWS FROM OPERATING ACTIVITIES:		
Cash received from customers and users	$ 366,925	$ 366,039
Cash paid to suppliers and employees	(270,419)	(267,768)
Other receipts	6,829	7,174
Net cash provided by operating activities	103,335	105,445
CASH FLOWS FROM NON-CAPITAL FINANCING ACTIVITIES:		
Transfers out - contributions to the City's general fund	(40,073)	(39,230)
Payment on pension obligation bonds	(1,894)	(712)
Cash received on advances to other funds of the City	316	683
Net cash used by non-capital financing activities	(41,651)	(39,259)
CASH FLOWS FROM CAPITAL AND RELATED FINANCING ACTIVITIES:		
Purchase of utility plant	(27,460)	(27,999)
Proceeds from the sale of utility plant	671	426
Payment on bond defeasance	(11,005)	-
Principal paid on long-term obligations	(14,602)	(14,109)
Interest paid on long-term obligations	(25,894)	(26,274)
Capital contributions	3,154	2,285
Net cash used by capital and related financing activities	(75,136)	(65,671)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Proceeds from investment securities	13,895	9,452
Income from investments	2,442	1,568
Net cash provided by investing activities	16,337	11,020
Net increase in cash and cash equivalents	2,885	11,535
CASH AND CASH EQUIVALENTS, BEGINNING OF YEAR **(including $47,133 and $41,847 at June 30, 2017 and June 30, 2016, respectively, reported in restricted accounts)**	302,629	291,094
CASH AND CASH EQUIVALENTS, END OF YEAR **(including $48,360 and $47,133 at June 30, 2018 and June 30, 2017, respectively, reported in restricted accounts)**	$ 305,514	$ 302,629
RECONCILIATION OF OPERATING INCOME TO NET CASH PROVIDED BY OPERATING ACTIVITIES:		
Operating income	$ 55,584	$ 74,070
Adjustments to reconcile operating income to net cash provided by operating activities:		
Depreciation	33,585	32,642
Increase (decrease) in allowance for uncollectible accounts	120	(241)
Decrease (increase) in accounts receivable	2,575	(742)
Decrease (increase) in prepaid expenses	540	(1,183)
Increase in unamortized purchased power	(2,080)	(1,591)
Increase (decrease) in accounts payable and other accruals	752	(2,650)
(Decrease) increase in compensated absences	(287)	44
Increase (decrease) in Public Benefit Programs payable	2	(1,614)
Increase (decrease) in unearned revenue	10	(274)
Increase in customer deposits	401	956
Decrease in decommissioning liability	(4,097)	(4,219)
Increase in advance from other funds of the City - pension obligations	-	2,680
Changes in net pension liability and related deferred outflows and inflows of resources	9,055	(248)
Changes in other postemployment benefits liability and related deferred inflows of resources	346	641
Other receipts	6,829	7,174
Net cash provided by operating activities	$ 103,335	$ 105,445
SCHEDULE OF NON-CASH INVESTING, CAPITAL AND FINANCING ACTIVITIES:		
Capital contributions - capital assets	17,012	17,317
(Decrease) increase in fair value of investments	(79)	902

See accompanying notes to the financial statements

ELECTRIC UTILITY: NOTES TO THE FINANCIAL STATEMENTS

NOTE 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

Effective July 1, 2017, the accompanying financial statements reflect the implementation of Governmental Accounting Standards Board (GASB) Statement No. 75, *Accounting and Financial Reporting for Postemployment Benefits Other Than Pensions* (GASB 75). The primary objective of this statement is to improve accounting and financial reporting by state and local governments in regards to postemployment benefits other than pensions (OPEB). These improvements provide users of financial statements decision-useful information, support assessments of accountability and interperiod equity, and create additional transparency. GASB 75 accomplishes this by requiring recognition of the entire OPEB liability, a more comprehensive measure of OPEB expense, along with new note disclosures and required supplementary information. For further details, refer to Note 6.

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. 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 $15,270 at June 30, 2018, and $16,868 at June 30, 2017.

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

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 PLANT AND DEPRECIATION

The Electric Utility defines capital assets as assets with an initial, individual cost of more than five thousand dollars and an estimated useful life in excess of one year. Electric Utility plant assets are valued at historical cost or estimated historical cost, if actual historical cost is not available. Costs include labor; materials; interest during construction; 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.

Interest incurred during the construction phase is reflected in the capitalized value of the asset constructed. For fiscal years ended June 30, 2018 and 2017, the Electric Utility capitalized net interest costs of $1,667 and $1,429, respectively. Total interest expense incurred by the Electric Utility was $25,120 and $25,553, respectively.

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 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 INVESTMENTS

In accordance with the Electric Utility policy, the Electric 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 Electric Utility does not own specific, identifiable investments of the pool. The pooled interest earned is allocated monthly based on the month end cash balances.

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (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 1 and level 3 inputs.

City-wide information concerning cash and investments as of June 30, 2018, 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 "Comprehensive Annual Financial Report" (CAFR).

CASH AND INVESTMENTS AT FISCAL AGENTS

Cash and investments maintained by fiscal agents are considered restricted by the Electric Utility and are used to fund construction of capital assets. 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 San Onofre Generating Stations (SONGS).

UNRESTRICTED 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 considered unrestricted assets and represent the portion of unrestricted reserves 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.

Unrestricted designated cash reserve balances as of June 30, 2018 and 2017 were as follows: Additional Decommissioning Liability Reserve $8,245 and $6,590, Customers Deposits $4,562 and $4,385, Capital Repair and Replacement Reserve $4,865 and $3,119, Electric Reliability Reserve $62,800 and $54,242, and Mission Square Improvement Reserve $1,244 and $734. In addition, a Dark Fiber designated reserve was approved by City Council on July 11, 2017 to account for fiber lease activities. As of June 30, 2018, the balance in the Dark Fiber Reserve was $2,303. In June 2017, the Board of Public Utilities and City Council approved the establishment of a bond defeasance designated cash reserve account and authorized the transfer of settlements and cost recoveries in the amount of $11,244 to the designated reserve for bond defeasance. As of June 30, 2018, bond defeasance reserve has been fully utilized to partially defease existing revenue bonds. The combined total for these reserves was $84,019 and $ 80,314 at June 30, 2018 and 2017, 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 other funds of the City have been recorded as a result of agreements between the Electric Utility and the City. The balances as of June 30, 2018 and 2017 are $4,532 and $4,848, 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.

The Electric Utility has determined that its interest rate swaps associated with variable rate obligations are derivative instruments under GASB 53. See Note 4 Long-Term Obligations 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.

NUCLEAR DECOMMISSIONING LIABILITY

Federal regulations require the Electric Utility to provide for the future decommissioning of its ownership share of the nuclear units at San Onofre. The Electric Utility has established trust accounts to accumulate resources for the decommissioning of the nuclear power plant and restoration of the beachfront at San Onofre. Based on the most recent site-specific decommissioning cost estimate as of March 2018, the Electric Utility has fully funded the SONGS nuclear decommissioning liability. The Electric Utility has set aside $57,154 and $70,324 in cash investments with the trustee and $8,245 and $6,590 in an unrestricted designated decommissioning reserve as the Electric Utility's estimated share of the decommissioning cost of SONGS as of June 30, 2018 and 2017, respectively, and these amounts are reflected as restricted assets and unrestricted cash and cash equivalents, respectively, on the Statements of Net Position. There is much uncertainty as to future unknown costs to decommission SONGS. Although management believes the current cost estimate is the upper bound of decommissioning obligations, the Electric Utility has conservatively continued to set aside $1,581 per year in an unrestricted designated cash reserve for unexpected costs not contemplated in the current estimates. See Note 9 for further discussion on SONGS nuclear decommissioning liability.

CAPITAL LEASES

The Electric Utility has entered into sixteen capital lease agreements as a lessee for financing sixteen compressed natural gas heavy duty service trucks. All leases have seven year terms of monthly payments with interest rates ranging from 2.0 percent to 2.5 percent. The total gross value of all existing leases is $5,715 with depreciation over the seven year terms of the leases using the straight-line method.
As of June 30, 2018 and 2017, the total liability was $3,098 and $3,905, respectively, with the current portion included in accounts payable and other accruals. The remaining annual lease payments for the life of the leases is $881 in fiscal year ended June 30, 2019, $868 in fiscal year ended June 30, 2020, $559 annually in fiscal years ended June 30, 2021 and 2022, and $367 in fiscal year ended June 30, 2023. Total outstanding lease payments are $3,234, with $3,098 representing the present value of the net minimum lease payments and $135 representing interest.

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

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, 2018 and 2017 was $6,397 and $5,996, respectively.

COMPENSATED ABSENCES

The accompanying financial statements include accruals for salaries, fringe benefits and compensated absences due to employees at June 30, 2018 and 2017. 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 $5,068 at June 30, 2018 and $4,985 at June 30, 2017.

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 primarily 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.

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, including the Electric Utility Plant with a limit of $1 billion.

City-wide information concerning risks, insurance policy limits and deductibles and designation of general fund balance for risk for the year ended June 30, 2018, may be found in the notes to the City's financial statements in the City's CAFR.

Although the ultimate amount of losses incurred through June 30, 2018 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 $627 and $620 for the years ended June 30, 2018 and 2017, respectively. Any losses above the City's reserves would be covered through increased rates charged to the Electric 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 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 5.

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. In order to improve the financial reporting of these benefits, the Electric Utility has implemented GASB 75, which is explained in details under New Accounting Pronouncements and in Note 6.

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 changes in derivative values, loss on refunding and deferred outflows related to pension 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 deferred inflows related to pension 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."

NOTE 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, 2018 and 2017, $40,073 and $39,230, respectively was transferred representing 11.5 percent.

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. 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.

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 adopts the Electric Utility's budget in June biennially via resolution.

RECLASSIFICATIONS

Certain reclassifications have been made to prior year's financial statements to conform with the current year's presentation. Such reclassifications have no effect on the net position or the changes in net position.

NOTE 2. CASH AND INVESTMENTS

Cash and investments at June 30, 2018 and 2017, consist of the following (in thousands):

	June 30, 2018	June 30, 2017
	Fair Value	
Equity interest in City Treasurer's investment pool	$ 305,514	$ 302,629
Cash and investments at fiscal agent	69,047	82,941
Total cash and investments	$ 374,561	$ 385,570

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

	June 30, 2018	June 30, 2017
Unrestricted cash and cash equivalents	$ 257,155	$ 255,496
Restricted cash and cash equivalents	48,359	47,133
Restricted cash and investments at fiscal agent	69,047	82,941
Total cash and investments	$ 374,561	$ 385,570

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.

NOTE 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, 2018 and 2017:

Investment Type	June 30, 2018 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	$ 2,745	$ -	$ 2,745	$ -	$ -
US Treasury notes/bonds	46,314	-	46,314	-	-
Investment contracts	10,761	-	-	-	10,761
Corp medium term notes	9,227	-	9,227	-	-
City Treasurer's investment pool [1]					
Money market funds	72,037	-	72,037	-	-
Federal agency securities	3,847	-	3,847	-	-
US Treasury notes/bonds	145,973	-	145,973	-	-
Corp medium term notes	17,371	-	17,371	-	-
State investment pool	62,702	-	-	-	62,702
Neg certificate of deposit	3,584	-	3,584	-	-
Total	$ 374,561	$ -	$ 301,098	$ -	$ 73,463

Investment Type	June 30, 2017 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	$ 54,697	$ -	$ 54,697	$ -	$ -
Federal agency securities	13,485	-	13,485	-	-
Investment contracts	10,761	-	-	-	10,761
Corp medium term notes	3,998	-	3,998	-	-
City Treasurer's investment pool [1]					
Money market funds	46,303	-	46,303	-	-
Federal agency securities	5,440	-	5,440	-	-
US Treasury notes/bonds	166,652	-	166,652	-	-
Corp medium term notes	9,270	-	9,270	-	-
State investment pool	68,967	-	-	-	68,967
Neg certificate of deposit	5,997	-	5,997	-	-
Total	$ 385,570	$ -	$ 305,842	$ -	$ 79,728

[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 CAFR.

NOTE 2. CASH AND INVESTMENTS (CONTINUED)

Cash and investments distribution by maturities as of June 30, 2018 and 2017, are as follows:

		Remaining Maturity (In Months)			
Investment Type	June 30, 2018 Fair Value	12 Months or less	13 to 24 Months	25 to 60 Months	More than 60 Months
Held by fiscal agent					
Money market funds	$ 2,745	$ 2,745	$ -	$ -	$ -
US Treasury notes/bonds	46,314	10,962	8,890	26,462	-
Investment contracts	10,761	-	-	-	10,761
Corp medium term notes	9,227	2,880	3,379	2,968	-
City Treasurer's investment pool [1]					
Money market funds	72,037	72,037	-	-	-
Federal agency securities	3,847	-	-	3,847	-
US Treasury notes/bonds	145,973	19,723	68,207	58,043	-
Corp medium term notes	17,371	4,114	7,207	6,050	-
State investment pool	62,702	62,702	-	-	-
Negotiable certificate of deposit	3,584	2,162	477	945	-
Total	$ 374,561	$ 177,325	$ 88,160	$ 98,315	$ 10,761

		Remaining Maturity (In Months)			
Investment Type	June 30, 2017 Fair Value	12 Months or less	13 to 24 Months	25 to 60 Months	More than 60 Months
Held by fiscal agent					
Money market funds	$ 54,697	$ 54,697	$ -	$ -	$ -
Federal agency securities	13,485	13,485	-	-	-
Investment contracts	10,761	-	-	-	10,761
Corp medium term notes	3,998	3,998	-	-	-
City Treasurer's investment pool [1]					-
Money market funds	46,303	46,303	-	-	-
Federal agency securities	5,440	5,440	-	-	-
US Treasury notes/bonds	166,652	24,612	53,225	88,815	-
Corp medium term notes	9,270	4,690	4,580	-	-
State investment pool	68,967	68,967	-	-	-
Negotiable certificate of deposit	5,997	1,995	2,401	1,601	-
Total	$ 385,570	$ 224,187	$ 60,206	$ 90,416	$ 10,761

[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 CAFR.

NOTE 2. CASH AND INVESTMENTS (CONTINUED)

Presented below is the actual rating as of June 30, 2018 and 2017 for each investment type:

Investment Type	June 30, 2018 Fair Value	Rating as of Year End AAA	AA	A	Unrated
Held by fiscal agent					
Money market funds	$ 2,745	$ 1,506	$ -	$ 1,239	$ -
US Treasury notes/bonds	46,314	46,314	-	-	-
Investment contracts	10,761	-	-	-	10,761
Corp medium term notes	9,227	2,880	2,968	3,379	
City Treasurer's investment pool [1]					
Money market funds	72,037	-	69,557	2,480	-
Federal agency securities	3,847	3,847	-	-	-
US Treasury notes/bonds	145,973	145,973	-	-	-
Corp medium term notes	17,371	-	17,371	-	-
State investment pool	62,702	-	-	-	62,702
Neg certificate of deposit	3,584	-	-	-	3,584
Total	$ 374,561	$ 200,520	$ 89,896	$ 7,098	$ 77,047

Investment Type	June 30, 2017 Fair Value	Rating as of Year End AAA	AA	A	Unrated
Held by fiscal agent					
Money market funds	$ 54,697	$ 52,815	$ -	$ 1,882	$ -
Federal agency securities	13,485	13,485	-	-	-
Investment contracts	10,761	-	-	-	10,761
Corp medium term notes	3,998	-	-	3,998	-
City Treasurer's investment pool [1]					
Money market funds	46,303	-	43,569	2,734	-
Federal agency securities	5,440	5,440	-	-	-
US Treasury notes/bonds	166,652	166,652	-	-	-
Corp medium term notes	9,270	1,895	6,408	967	-
State investment pool	68,967	-	-	-	68,967
Neg certificate of deposit	5,997	-	-	-	5,997
Total	$ 385,570	$ 240,287	$ 49,977	$ 9,581	$ 85,725

[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 CAFR.

NOTE 3. UTILITY PLANT

The following is a summary of changes in utility plant during the fiscal years ended June 30, 2018 and 2017 (in thousands):

	Balance As of 6/30/2016	Additions	Retirements/ Transfers	Balance As of 6/30/2017	Additions	Retirements/ Transfers	Balance As of 6/30/2018
Production	$ 267,312	$ -	$ -	$ 267,312	$ -	$ -	$ 267,312
Transmission	44,415	553	-	44,968	83	(44)	45,007
Distribution	584,010	18,026	(730)	601,306	27,721	(1,136)	627,891
General	106,746	3,463	(310)	109,899	709	(216)	110,392
Intangibles	18,961	1,990	-	20,951	521	-	21,472
Depreciable utility plant	1,021,444	24,032	(1,040)	1,044,436	29,034	(1,396)	1,072,074
Less accumulated depreciation:							
Production	(70,823)	(8,946)	-	(79,769)	(8,946)	-	(88,715)
Transmission	(16,990)	(910)	-	(17,900)	(914)	44	(18,770)
Distribution	(222,062)	(15,986)	727	(237,321)	(16,471)	1,044	(252,748)
General	(32,464)	(4,816)	305	(36,975)	(4,959)	216	(41,718)
Intangibles	(1,827)	(1,984)	-	(3,811)	(2,295)	-	(6,106)
Accumulated depreciation	(344,166)	(32,642)	1,032	(375,776)	(33,585)	1,304	(408,057)
Net depreciable utility plant	677,278	(8,610)	(8)	668,660	(4,551)	(92)	664,017
Land	21,439	16,406	-	37,845	14,266	-	52,111
Intangibles, non-amortizable	10,651	-	-	10,651	-	-	10,651
Construction in progress	45,326	29,155	(22,845)	51,636	28,834	(25,995)	54,475
Nondepreciable utility plant	77,416	45,561	(22,845)	100,132	43,100	(25,995)	117,237
Total utility plant	$ 754,694	$ 36,951	$ (22,853)	$ 768,792	$ 38,549	$ (26,087)	$ 781,254

NOTE 4. LONG-TERM OBLIGATIONS

The following is a summary of changes in long-term obligations during the fiscal years ended June 30, 2018 and 2017 (in thousands):

	Balance As of 6/30/2016	Additions	Reductions	Balance As of 6/30/2017	Additions	Reductions	Balance As of 6/30/2018	Due Within One Year
Revenue bonds	$575,048		$ (14,131)	$560,917		$ (25,578)	$ 535,339	$14,445
Pension obligation bonds	10,084	2,940	(712)	12,312		(1,894)	10,418	2,018
Compensated absences	4,887	4,259	(4,161)	4,985	4,556	(4,473)	5,068	4,547
Nuclear decommissioning liability	68,893		(4,220)	64,673	529	(4,625)	60,577	5,457
Capital leases	4,694		(789)	3,905		(807)	3,098	824
Total long-term obligations	$663,606	$ 7,199	$ (24,013)	$646,792	$ 5,085	$ (37,377)	$ 614,500	$27,291

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

PENSION OBLIGATION BONDS PAYABLE

	June 30, 2018	June 30, 2017
$30,000 2005 Taxable Pension Obligation Bonds Series A: fixed rate bonds issued by the City due in annual installments from $630 to $3,860 through June 2020, interest from 3.9 to 4.8 percent. The Electric Utility's proportional share of the outstanding debt is 29.6 percent.	1,933	2,964
$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, interest from 1.3 to 3.1 percent. The Electric Utility's proportional share of the outstanding debt is 29.6 percent.	8,485	9,348
Total pension obligation bonds payable	10,418	12,312

NOTE 4. LONG-TERM OBLIGATIONS (CONTINUED)

REVENUE BONDS PAYABLE

	June 30, 2018	June 30, 2017
$141,840 2008 Electric Refunding/Revenue Bonds:		
A - $84,515 2008 Series A Bonds - variable rate bonds due in annual principal installments from $4,575 to $7,835 through October 1, 2029. Interest rate is subject to weekly repricing (net interest rate, including swaps, at June 30, 2018 was 3.0 percent). Partially refunded $13,975 on July 25, 2013 with the 2013 Electric Revenue Refunding Bonds	70,540	70,540
C - $57,325 2008 Series C Bonds - variable rate bonds due in annual principal installments from $700 to $5,200 through October 1, 2035. Interest rate is subject to weekly repricing (net interest rate, including swaps, at June 30, 2018 was 3.1 percent). Partially refunded $11,775 on July 25, 2013 with the 2013 Electric Revenue Refunding Bonds	41,975	41,975
$209,740 2008 Electric Revenue Series D Bonds: fixed rate bonds due in annual principal installments from $3,560 to $22,925 through October 1, 2038, interest from 3.6 to 5.0 percent. Partially defeased $11,005 on May 8, 2018.	195,275	209,740
$34,920 2009 Electric Refunding/Revenue Series A Bonds: fixed rate bonds due in final principal installment of $1,275 on October 1, 2018, interest of 4.0 percent.	1,275	2,490
$140,380 2010 Electric Revenue Bonds:		
A - $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, from October 1, 2020 through October 1, 2040, interest from 3.9 to 4.9 percent	133,290	133,290
B - $7,090 2010 Electric Revenue Series B Bonds: fixed rate bonds due in annual principal installments from $2,210 to $2,440 through October 1, 2019, interest from 4.0 to 5.0 percent	4,650	6,995
$56,450 2011 Electric Revenue/Refunding Series A Bonds: variable rate bonds due in annual principal installments from $725 to $5,175 through October 1, 2035. Interest rate is subject to weekly repricing (net interest rate, including swaps, at June 30, 2018 was 3.1 percent). Partially refunded $11,825 on July 25, 2013 with the 2013 Electric Revenue Refunding Bonds	41,925	41,925
$79,080 2013 Electric Revenue Refunding Series A Bonds: fixed rate bonds due in annual principal installments from $795 to $2,625 through October 1, 2043, interest from 3.5 to 5.3 percent	39,785	46,560
Total electric revenue bonds payable	528,715	553,515
Total electric revenue and pension obligation bonds payable	539,133	565,827
Unamortized bond premium	6,624	7,402
Total electric revenue and pension obligation bonds payable, including bond premium	545,757	573,229
Less current portion of revenue and pension obligation bonds payable	(16,463)	(15,689)
Total long-term electric revenue and pension obligation bonds payable	$ 529,294	$ 557,540

NOTE 4. LONG-TERM OBLIGATIONS (CONTINUED)

Revenue and pension obligation bonds annual debt service requirements to maturity as of June 30, 2018 are as follows (in thousands):

	2019	2020	2021	2022	2023	2024-2028	2029-2033	2034-2038	2039-2043	2044-2048	Total
Principal	$ 16,463	$ 16,673	$ 16,442	$ 17,011	$ 17,623	$ 94,804	$ 116,230	$ 134,915	$ 106,347	$ 2,625	$ 539,133
Interest	$ 23,628	$ 22,992	$ 22,376	$ 21,771	$ 21,135	$ 93,441	$ 70,830	$ 43,040	$ 9,449	$ 66	$ 328,728
Total	$ 40,091	$ 39,665	$ 38,818	$ 38,782	$ 38,758	$ 188,245	$ 187,060	$ 177,955	$ 115,796	$ 2,691	$ 867,861

For fiscal year ended June 30, 2018, the City restructured the presentation of the long term pension obligation bonds from advances from other funds to long term obligations. 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. The Electric Utility's proportional share of the outstanding principal amount of the bonds was $10,418 and $12,312 as of June 30, 2018 and 2017, 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 CAFR for the fiscal year ended June 30, 2018.

In May 2018, the Electric Utility defeased $11,005 of the total outstanding $206,280 of Electric Revenue Bonds, Issue 2008D with monies received from settlements and cost recoveries associated with the early closure of the SONGS Units 2 and 3. The partial defeasance related to bond proceeds that funded part of the Steam Generator Replacement Project and other SONGS capital costs. The partial bond defeasance reduced debt and realized interest savings of $10,233 over the remaining 20-year life of the bonds. As of June 30, 2018, the outstanding debt related to the 2008D Bond Issuance was $195,275.

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. For June 30, 2018 and 2017, 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)	Annual Debt Service Payments	Debt Service Coverage Ratio
June 30, 2018	Electric revenues	$ 110,331	$ 40,720	2.71
June 30, 2017	Electric revenues	$ 116,958	$ 39,585	2.95

[1] Excludes GASB 68 Accounting and Financial Reporting for Pension non-cash adjustments of $9,056 and ($248) as expenses for June 30, 2018 and 2017 respectively.

LETTERS OF CREDIT

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

NOTE 4. LONG-TERM OBLIGATIONS (CONTINUED)

Debt Issue	LOC Provider	LOC Expiration Date	Annual Commitment Fee
2008 Electric Refunding/Revenue Bonds Series A	Barclays Bank, PLC	2021	0.325%
2008 Electric Refunding/Revenue Bonds Series C	Barclays Bank, PLC	2021	0.325%

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.

Liquidity advances drawn against the LOC that are not repaid will be converted to an installment loan with principal to be paid quarterly not to exceed a 5-year period. The Electric Utility would be required to pay annual interest equal to the highest of 8 percent, the Prime Rate plus 2.5 percent, the Federal Funds Rate plus 2.5 percent and 150 percent of the yield on the 30-year U.S. Treasury Bond. No amounts have ever been drawn against the two LOCs due to a failed remarketing.

The various indentures allow the Electric Utility to convert the mode of the debt in the case of a failed remarketing.

INTEREST RATE SWAPS ON REVENUE BONDS

The Electric Utility has three cash flow hedging derivative instruments, which are 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 is 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 has been recorded and deferred on the Statements of Net Position.

A summary of the derivative activity for the year ended June 30, 2018 is as follows:

	Notional Amount	Fair Value as of 6/30/2018	Change in Fair Value for Fiscal Year
2008 Electric Refunding/Revenue Bonds Series A	$ 68,525	$ (4,777)	$ 2,888
2008 Electric Refunding/Revenue Bonds Series C	$ 41,975	$ (5,234)	$ 2,207
2011 Electric Refunding/Revenue Bonds Series A	$ 41,925	$ (5,217)	$ 2,202

***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 existing swap agreements, the Electric Utility pays the counterparty a fixed payment and receives a variable payment computed as 62.68 percent of the London Interbank Offering Rate ("LIBOR") one month index plus 12 basis points. The swaps have notional amounts equal to the principal amounts stated above. The notional value of the swaps and the principal amounts of the associated debt decline by $4,575 to $7,835 (2008 Series A), $700 to $5,200 (2008 Series C) and $725 to $5,175 (2011 Series A) until the debt is completely retired in fiscal years 2030 (2008 Series A) and 2036 (2008 Series C and 2011 Series A).

The bonds and the related swap agreements for the Electric Refunding/Revenue 2008 (Series A) Bonds mature on October 1, 2029 and the 2008 (Series C) and 2011 (Series A) Bonds mature on October 1, 2035. As of June 30, 2018, rates were as follows:

		2008 Electric Refunding/Revenue Series A Bonds	2008 Electric Refunding/Revenue Series C Bonds	2011 Electric Refunding/Revenue Series A Bonds
Interest rate swap:	**Terms**	**Rates**	**Rates**	**Rates**
Fixed payment to counterparty	Fixed	3.11100%	3.20400%	3.20100%
Variable payment from counterparty	62.68 LIBOR + 12bps	(0.47498%)	(0.47558%)	(0.44435%)
Net interest rate swap payments		2.63602%	2.72842%	2.75665%
Variable-rate bond coupon payments		0.39419%	0.39465%	0.36625%
Synthetic interest on bonds		3.03021%	3.12307%	3.12290%

Fair value**:** As of June 30, 2018, in connection with all swap agreements, the transactions had a total negative fair value of ($15,228). Because the coupons on the Electric 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 swaps, 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.

Credit risk**:** As of June 30, 2018, the Electric Utility was not exposed to credit risk because the swaps had a negative fair value. The swaps counterparties, J.P. Morgan Chase & Co. and Bank of America Corp., were rated A- and BBB+ respectively by Standard & Poor's (S&P). To mitigate the potential for credit risk, the swap agreements require the fair value of the swaps to be collateralized by the counterparty with U.S. Government securities if the counterparties' rating decreases to negotiated trigger points. Collateral would be posted with a third-party custodian. At June 30, 2018, there is no requirement for collateral posting for any of the outstanding swaps.

Basis risk**:** As noted above, the swaps expose the Electric Utility to basis risk should the relationship between LIBOR 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 Electric Utility if either counterparty's credit quality falls below "BBB-" as issued by S&P. The Electric 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 Electric 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, 2018, 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 in the table below. As rates vary, variable-rate bond interest payments and net swap payments will vary.

Fiscal Year Ending June 30,	Variable-Rate Bonds Principal	Interest	Interest Rate Swaps, Net	Total
2019	$ 6,375	$ 625	$ 4,373	$ 11,373
2020	8,300	592	4,150	13,042
2021	8,600	558	3,904	13,062
2022	8,950	521	3,649	13,120
2023	9,200	483	3,388	13,071
2024-2028	37,875	1,952	13,799	53,626
2029-2033	45,115	1,078	7,776	53,969
2034-2038	30,025	164	1,185	31,374
Total	$ 154,440	$ 5,973	$ 42,224	$ 202,637

NOTE 5. EMPLOYEE RETIREMENT PLAN

PLAN DESCRIPTION

The City contributes to 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. 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.calpersca.gov. The Electric 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 percent 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 –
    - The retirement formula is 2.7 percent at age 55 for employees hired before October 19, 2011. Effective January 1, 2018 for unrepresented employees (Sr. Management, Management, Professional, Para-professional, Supervisory, Confidential, and Executive units), the employees were required to pay 2 percent of the employee contribution of their pensionable income, with the City contributing the other 6 percent. Effective January 1, 2019, employees will be required to pay an additional portion of their pensionable income. This portion is a three year increase of 2 percent (2019), 2 percent (2020) and 2 percent (2021). By 2021, employees will be contributing the entire 8 percent of their pensionable income.

    - The retirement formula is 2.7 percent at age 55 for SEIU employees hired before June 7, 2011. The employee is required to pay 6 percent of their pensionable income with the City contributing the other 2 percent. Effective January 1, 2019, employees will be required to pay an additional portion of their pensionable income. This portion is a two year increase of 1 percent (2019) and 1 percent (2020). By 2020, employees will be contributing the entire 8 percent of their pensionable income.

  - The retirement formula is 2.7 percent at age 55 for IBEW employees hired before October 19, 2011. Effective November 1, 2017 employees contributed 2 percent of their total pensionable income with the City paying the remaining 6 percent. Effective November 1, 2018, employees will be required to pay an additional portion of their pensionable income. This portion is a three year increase of 2 percent (2018), 2 percent (2019) and 2 percent (2020). By 2020, employees will be contributing the entire 8 percent of their pensionable income.

- 2nd Tier - The retirement formula is 2.7 percent at age 55, and:
  - SEIU employees hired on or after June 7, 2011 pay their share (8 percent) of contributions.
  - All other miscellaneous employees hired on or after October 19, 2011 pay their share (8 percent) of contributions.

- 3rd Tier – The retirement formula is 2 percent at age 62 for new members hired on or after January 1, 2013 and the employee must pay the employee share ranging from 7 percent to 8 percent based on bargaining group classification. 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.

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.

EMPLOYEES COVERED

As of measurement date June 30, 2017 and 2016, the following employees, City-wide, were covered by the benefit terms of the Plan:

	Measurement Date	
	June 30, 2017	**June 30, 2016**
Inactive employees or beneficiaries currently receiving benefits	2,114	2,040
Inactive employees entitled to but not yet receiving benefits	1,325	1,317
Active employees	1,599	1,536

NOTE 5. EMPLOYEE RETIREMENT PLAN (CONTINUED)

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 June 30, 2018, the net pension liability of the Plan is measured as of June 30, 2017, using an annual actuarial valuation as of June 30, 2016 rolled forward to June 30, 2017 using standard update procedures. For fiscal year June 30, 2017, the net pension liability of the Plan is measured as of June 30, 2016, using an annual actuarial valuation as of June 30, 2015 rolled forward to June 30, 2016 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 June 30, 2016 and 2015 actuarial valuations were determined using the following actuarial assumptions:

	Miscellaneous - Current Year	**Miscellaneous - Prior Year**
Valuation Date	June 30, 2016	June 30, 2015
Measurement Date	June 30, 2017	June 30, 2016
Actuarial Cost Method	Entry-Age Normal Cost Method	Entry-Age Normal Cost Method
Actuarial Assumptions:		
Discount rate	7.15%	7.65%
Inflation	2.75%	2.75%
Payroll growth	3.00%	3.00%
Projected salary increase	(1)	(1)
Investment rate of return [2]	7.50%	7.50%
Mortality	(3)	(3)

[1] Depending on age, service and type of employment.

[2] Net of pension plan investment expenses, including inflation.

[3] The probabilities of mortaility are based on the 2014 CalPERS Experience Study for the period from 1997 to 2011. Pre-retirement mortality rates include 20 years of projected mortality improvement using Scale BB published by the Society of Actuaries.

DISCOUNT RATE

The discount rate used to measure the Plan's total pension liability was 7.15 percent and 7.65 percent for measurement date as of June 30, 2017 and 2016, respectively. To determine whether the municipal bond rate should be used in the calculation of a discount rate for the Plan, CalPERS stress tested plans that would most likely result in a discount rate that would be different from the actuarially assumed discount rate. Based on the testing, none of the tested plans run out of assets. Therefore, the discount rates used to measure total pension liability are adequate and the use of the municipal bond rate calculation is not necessary. The long term expected discount rates are applied to all plans in the Public Employees Retirement Fund. The stress test results are presented in a detailed report called “GASB Crossover Testing Report” that can be obtained from the CalPERS website.

The long-term expected rate of return on pension plan investments was determined using a building-block method in which best-estimate ranges of 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 as well as the expected pension fund cash flows. Using historical returns of all the funds’ asset classes, expected compound returns were calculated over the short-term (first 10 years) and the long-term (11-60 years) using a building-block approach. Using the expected nominal returns for both short-term and long-term, the present value of benefits was calculated for each fund. The expected rate of return was set by calculating the single equivalent expected return that arrived at the same present value of benefits for cash flows as the one calculated using both short-term and long-term returns. The expected rate of return was then set equivalent to the single equivalent rate calculated above and rounded down to the nearest one quarter of one percent.

The table below reflects long-term expected real rate of return by asset class. The rate of return was calculated using the capital market assumptions applied to determine the discount rate and asset allocation. These geometric rates of return are net of administrative expenses.

June 30, 2017 Measurement Date

Asset Class	Current Target Allocation	Real Return Years 1 - 10 (1)	Real Return Years 11 + (2)
Global Equity	47.00%	4.90%	5.38%
Global Fixed Income	19.00%	0.80%	2.27%
Inflation Sensitive	6.00%	0.60%	1.39%
Private Equity	12.00%	6.60%	6.63%
Real Estate	11.00%	2.80%	5.21%
Infrastructure and Forestland	3.00%	3.90%	5.36%
Liquidity	2.00%	-0.40%	-0.90%

(1) An expected inflation of 2.50% used for this period.
(2) An expected inflation of 3.00% used for this period.

June 30, 2016 Measurement Date

Asset Class	Current Target Allocation	Real Return Years 1 - 10 (1)	Real Return Years 11 + (2)
Global Equity	51.00%	5.25%	5.71%
Global Fixed Income	20.00%	0.99%	2.43%
Inflation Sensitive	6.00%	0.45%	3.36%
Private Equity	10.00%	6.83%	6.95%
Real Estate	10.00%	4.50%	5.13%
Infrastructure and Forestland	2.00%	4.50%	5.09%
Liquidity	1.00%	-0.55%	-1.05%

(1) An expected inflation of 2.50% used for this period.
(2) An expected inflation of 3.00% used for this period.

NOTE 5. EMPLOYEE RETIREMENT PLAN (CONTINUED)

CHANGES IN THE NET PENSION LIABILITY

The changes in the Electric Utility's proportionate share of the net pension liability as of June 30, 2018 (measurement date June 30, 2017) and 2017 (measurement date June 30, 2016) for the Plan are as follows:

June 30, 2018		Net Pension Liabiltiy	Proportion of the Plan
Proportion - Reporting date June 30, 2018 (measurement date June 30, 2017)	$	108,886	32.04%
Proportion - Reporting date June 30, 2017 (measurement date June 30, 2016)		96,193	31.08%
Change - Increase / (Decrease)		12,693	0.96%
June 30, 2017			
Proportion - Reporting date June 30, 2017 (measurement date June 30, 2016)		96,193	31.08%
Proportion - Reporting date June 30, 2016 (measurement date June 30, 2015)		77,907	31.96%
Change - Increase / (Decrease)		18,286	(0.88%)

SENSITIVITY OF THE NET PENSION LIABILITY 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 7.15 percent and 7.65 percent for measurement date as of June 30, 2017 and 2016, respectively, 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, 2017			June 30, 2016	
	Discount Rate -1% (6.15%)	Current Discount Rate (7.15%)	Discount Rate +1% (8.15%)	Discount Rate -1% (6.65%)	Current Discount Rate (7.65%)	Discount Rate +1% (8.65%)
The Electric Utility's proportionate share of the Plan's net pension liability	$ 170,418	$ 108,886	$ 58,484	$ 149,304	$ 96,193	$ 52,510

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

NOTE 5. EMPLOYEE RETIREMENT PLAN (CONTINUED)

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

For the fiscal years ended June 30, 2018 and 2017, the Electric Utility recognized pension expense of $18,169 and $9,199, respectively. At June 30, 2018 and 2017, the Electric Utility reported deferred outflows of resources and deferred inflows of resources related to pension from the following sources:

	June 30, 2018		June 30, 2017	
	Deferred Outflows of Resources	Deferred Inflows of Resources	Deferred Outflows of Resources	Deferred Inflows of Resources
Pension contributions subsequent to measurement date	$ 9,073	$ -	$ 9,447	$ -
Difference between actual and actuarial determined contribution	-	-	3,321	-
Changes in assumptions	17,082	-	-	(3,135)
Differences between expected and actual experience	-	(6,396)	-	(3,805)
Net differences between projected and actual earnings on plan investments	4,441	-	25,479	(10,745)
Total	$ 30,596	$ (6,396)	$ 38,247	$ (17,685)

$9,073 reported as deferred outflows of resources related to contributions subsequent to the measurement date will be recognized as a reduction of the net pension liability in the year ended June 30, 2019.

Amounts reported as deferred outflows of resources and deferred inflows of resources related to pensions will be recognized as pension expense as follows:

Year Ended June 30	Deferred Outflows/ (Inflows) of Resources
2019	3,210
2020	9,625
2021	4,651
2022	(2,359)
Total	$ 15,127

NOTE 6. OTHER POST-EMPLOYMENT BENEFITS (OPEB)

PLAN DESCRIPTION

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.

NOTE 6. OTHER POST-EMPLOYMENT BENEFITS (OPEB) (CONTINUED)

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.

As of measurement date June 30, 2017, the following employees, City-wide, were covered by the benefit terms:

	Measurement Date June 30, 2017
Inactive plan members or beneficiaries currently receiving benefits	304
Inactive plan members entitled to but not yet receiving benefits	-
Active plan members	2,121
Total	2,425

ACTUARIAL ASSUMPTIONS

The total OPEB liability was determined by actuarial valuation as of June 30, 2017 using the following actuarial assumptions:

	Current Year
Valuation Date	June 30, 2017
Measurement Date	June 30, 2017
Funding Policy	Pay-as-you-go for implicit rate subsidy
Actuarial Assumptions:	
Discount rate [1]	3.40%
Inflation rate	2.75%
Salary inflation	3.00%
Salary increases [2]	--
Mortality	CalPERS 2014 Experience Study

[1] The discount rate is the average, rounded to 5 basis points, of the range of 3-20 year municipal bond rate indices: S&P Municipal Bond 20 Year High Grade Rate Index, Bond Buyer 20-Bond GO Index, and Fidelity GO AA 20 Year Bond Index.

[2] The benefits are not payroll related but the City's cost for each individual's projected City contribution is allocated over their lifetime as a level-percentage of pay. For cost method purposes the merit increases from the most recent CalPERS pension plan valuation will be used.

NOTE 6. 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, including Public Benefits, proportionate share of the City's total OPEB liability, calculating using the healthcare trend rate of 6.00%/HMO and 6.50%/PPO, 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 (5.00%/HMO and 5.50%/PPO) or 1-percentage-point higher (7.00%/HMO and 7.50%/PPO) than the current rate:

	June 30, 2017 - Measurement Date		
	1% Decrease	**Current healthcare cost trend rates**	**1% Increase**
The Electric Utility's proportionate share of the City's total OPEB liability	$ 7,445	$ 8,283	$ 9,262

SENSITIVITY OF TOTAL OPEB LIABILITY TO CHANGES IN DISCOUNT RATES

The following presents the Electric Utility's, including Public Benefits, proportionate share of the City's total OPEB liability, calculating using the discount rate of 3.40%, 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 (2.40%) or 1-percentage-point higher (4.40%) than the current rate:

	June 30, 2017 - Measurement Date		
	1% Decrease (2.40%)	**Current Discount Rate (3.40%)**	**1% Increase (4.40%)**
The Electric Utility's proportionate share of the City's total OPEB liability	$ 8,981	$ 8,283	$ 7,648

CHANGE IN TOTAL OPEB LIABILITY

For fiscal year ended June 30, 2018, the Electric Utility's, including Public Benefits, recognized total OPEB expense of $697. The following table shows the change in the Electric Utility's, including Public Benefits, proportionate share of the City's total OPEB liability for the year ended June 30, 2018 (measurement date June 30, 2017):

June 30, 2018	Total OPEB Liability	Proportion to the City
Proportion - Reporting date June 30, 2018 (measurement date June 30, 2017)	$ 8,283	22.52%
Proportion - Beginning balance at July 1, 2017	8,233	22.53%
Change - Increase / (Decrease)	50	(0.01%)

NOTE 6. OTHER POST-EMPLOYMENT BENEFITS (OPEB) (CONTINUED)

DEFERRED OUTFLOWS/INFLOWS OF RESOURCES RELATED TO OPEB

At June 30, 2018, the Electric Utility, including Public Benefits, reported deferred inflows of resources related to OPEB from the following sources:

	Deferred Inflows of Resources
Changes of assumptions	$ 296
Total	$ 296

Amounts reported as deferred inflows of resources related to OPEB will be recognized in OPEB expense as follows:

Year Ended June 30	Deferred Inflows of Resources
2019	$ (42)
2020	(42)
2021	(42)
2022	(42)
2023	(42)
Thereafter	(86)
Total	$ 296

NOTE 7. 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. Accordingly, a reserve for regulatory requirements has been established by restricting assets and reserving a portion of net position. See Note 10 for additional information regarding the Cap-and-Trade 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 percent of the monthly accrued interest to be included in the reserve. Active electric revenue bonds requiring reserves are issues 2008A & C. Certain revenue/refunding bond issues are covered by a Surety Bond (2008D) and certain issues have no debt service reserve requirements (2009A, 2010A & B, 2011A and 2013A).

NOTE 8. 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, 2018 and 2017, the Electric Utility paid approximately $26,631 and $28,806, respectively, to SCPPA under various take-or-pay and renewable contracts that are described in greater detail in Note 10. 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 consist 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.

NOTE 9. 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 (see Note 1 for nuclear decommissioning liability).

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.

SONGS was operated and maintained by SCE, under an agreement with the City and SDG&E, which expires upon termination of the easement for the plant in 2024. 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 the SCE's decommissioning cost estimate document as of March 2018, total decommissioning costs for Units 2 and 3 are estimated at $4.7 billion of which the Electric Utility's share is $84 million.

Nuclear Decommissioning Funding and Liability**.** As of June 30, 2018, the Electric Utility has set aside $57,154 in cash investments with the trustee and $8,245 in an unrestricted 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, 2018, the Electric Utility has paid to date $23,512 in decommissioning obligations, which have been reimbursed by the trust funds.

As of June 30, 2018 and 2017, decommissioning liability balance was $60,577 and $64,673, respectively, with a portion reflected as current liabilities payable from restricted assets. Due to adequate funding in the liability, 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 will continue to set aside funds in the unrestricted designated decommissioning reserve of $1,581 per year, as approved by the Board of Public Utilities and City Council.

Contractual Matters**.** The replacement steam generators for Units 2 and 3 were designed and manufactured by Mitsubishi Heavy Industries (MHI) and were warranted for an initial period of 20 years from acceptance. MHI was contractually obligated to repair or replace defective items and to pay specified damages for certain repairs. MHI's liability under the purchase agreement is limited to $138,000 and excludes consequential damages, defined to include "the cost of replacement power." The limitations are subject to certain exceptions.

According to a news release issued by SCE on July 18, 2013, SCE served a formal Notice of Dispute on MHI and Mitsubishi Nuclear Energy Systems and an arbitration hearing for such dispute was set for March and April of 2016. The SCE/MHI arbitration hearings concluded on April 29, 2016. On March 13, 2017, the arbitration tribunal awarded the owners of SONGS $125,000 for the defective steam generators supplied by MHI. In addition, the tribunal ordered SONGS owners to pay MHI $58,000 in legal costs but rejected MHI's counterclaims. The Electric Utility was awarded an amount of $1,078, which was reported as other non-operating revenues on the Statements of Revenues, Expenses and Changes in Net Position for fiscal year ended June 30, 2017.

NOTE 10. COMMITMENTS

The Electric Utility has entered into 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 coal-fueled generating station, known as Intermountain Power Project (IPP), located in central Utah. The contract expires in 2027 and the debt fully matures in 2024.

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 1368 (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. On June 16, 2015, the City Council approved the Intermountain Power Project renewal agreements, including the Second Amendatory Power Sales Contract and the Renewal Power Sales Contract, and authorized participation in the IPP renewal subscription process. The Second Amendatory Power Sales Contract became effective March 16, 2016. The generation component of IPP under the Renewal Power Sales Contract (Repower Project) is envisioned to be a natural gas fueled combined cycle plant with total capacity of 1,200 MW. The Renewal Power Sales Contract contemplates a term of fifty years, through June 2077 for the Repower Project. The Electric Utility is authorized to participate in the subscription process for up to 5 percent of the Repower Project or approximately 60 MW. On January 5, 2017, the Electric Utility executed the Renewal Power Sales Contract and all other necessary documents for the first two rounds of the subscription process. 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. The IPP Repower Project renewal subscription process was completed after two rounds on January 17, 2017 and all entitlements in the project were fully subscribed. The Electric Utility's reduced power would allow it to diversify its energy portfolio in the future. Further, under the Renewal Power Sales Contract, the Electric Utility has 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.

The Electric Utility is a member of SCPPA, a joint powers agency (see Note 8). 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

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.

NOTE 10. COMMITMENTS (CONTINUED)

The outstanding debts associated with the take-or-pay obligations have fixed interest rates which range from 1.43 percent to 5.75 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	SCPPA			TOTAL
Debt Service Payment (in thousands) Year Ending June 30,	**Intermountain Power Project**	**Southern Transmission System**	**Mead-Phoenix Transmission**	**Mead-Adelanto Transmission**	**All Projects**
2019	$ 17,345	$ 7,893	$ 257	$ 2,881	$ 28,376
2020	17,232	6,913	254	2,859	27,258
2021	15,829	7,926	189	2,136	26,080
2022	10,834	9,448	-	-	20,282
2023	8,059	7,258	-	-	15,317
2024-2028	840	20,175	-	-	21,015
Total	$ 70,139	$ 59,613	$ 700	$ 7,876	$ 138,328

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 and vary each year. The costs incurred for the year ended June 30, 2018 and 2017, are as follows (in thousands):

FISCAL YEAR	Intermountain Power Project	Palo Verde Nuclear Generating Station	Southern Transmission System	Hoover Dam Uprating	Mead-Phoenix Transmission	Mead-Adelanto Transmission	All Projects
2018	$ 20,755	$ 3,653	$ 3,529	$ 14	$ 58	$ 302	$28,311
2017	$ 23,000	$ 3,285	$ 2,712	$ 58	$ 64	$ 254	$29,373

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 the 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 entitlement in the Hoover project through SCPPA terminated on September 30, 2017. While through SCPPA in March 2014, the Electric Utility prepaid its share of outstanding debt incurred by the Bureau of Reclamation in connection with the acquisition and construction of the Hoover Power Project Visitors Center and Air Slots. The payment of principal and interest on the debt was a component of the cost of power and energy payable by Hoover contractors, which included SCPPA participants that received power from the Hoover Power Project under agreements with the Western Area Power Administration. Because Bureau Debt had interest at rates that were substantially higher than current market interest rates, the Electric Utility elected to prepay the debt in order to realize savings on power costs in the future. The Electric Utility's share of the prepaid debt was recorded on the Statements of Net Position as unamortized purchased power to be amortized over the remaining term of the project through 2017. As of June 30, 2017, unamortized purchased power was $124. This balance was fully amortized as of June 30, 2018.

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 extends the Electric Utility's 30 MW entitlement in the Hoover project an additional 50 years. The IA is a supplemental agreement to the ESC that establishes administrative, budgetary and project oversight by creating project committees and process for decision making plant operations.

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 ($450 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 April 7, 2018, the Act limits liability from third-party claims to approximately $13.1 billion per incident. Under the industry wide retrospective assessment program provided for under the Act, assessments are limited to $127.3 million per reactor for each nuclear incident occurring at any nuclear reactor in the United States, with payments under the program limited to $19.0 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 and ownership in SONGS, the Electric Utility would be responsible for a maximum assessment of $5.8 million, limited to payments of $0.9 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 passed by the State Legislative and signed by the Governor. SBX1-2 revised the amount of statewide retail electricity sales from renewable resources in the State Renewable Energy Resources Program to 33 percent by December 31, 2020 in three stages: average of 20 percent of retail sales during 2011-2013; 25 percent of retail sales by December 31, 2016; and 33 percent of retail sales by December 31, 2020. The Riverside Public Utilities Board and City Council approved the 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 implementing the new RPS mandates on May 3, 2013 and May 14, 2013, respectively. The Electric Utility met the 20 percent mandates from 2011-2013 and the 25 percent mandate by December 31, 2016. 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 2017, renewable resources provided 36 percent of retail sales requirements.

On September 11, 2015, California legislature passed Senate Bill 350 (SB 350) increasing the RPS mandate beyond December 31, 2020 above 33 percent to 50 percent by December 31, 2030. SB 350 was signed into law by the Governor on October 7, 2015. The Electric Utility expects to be able to substantially meet the increased RPS mandates imposed by SB 350 with the portfolio of renewable resources outlined below.

On September 10, 2018, the 100 Percent Clean Energy Act of 2018 (Senate Bill 100) was signed into law by the California Governor. This bill further increases the RPS goals of SBX1-2 and SB 350 by maintaining the 33 percent RPS target by December 31, 2020, while 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

NOTE 10. COMMITMENTS (CONTINUED)

Commission will have further guidance and enforcement procedures for publicly owned utilities. 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.

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

Supplier	Type	Maximum Contract [1]	Contract Expiration	Estimated Annual Cost For 2019
Salton Sea Power LLC	Geothermal	46.0 MW	5/31/2020	$ 29,165
Wintec Energy, Ltd.	Wind	1.3 MW	12/30/2018	124
WKN Wagner	Wind	6.0 MW	12/22/2032	1,318
SunEdison - AP North Lake	Photovoltaic	20.0 MW	8/11/2040	4,623
Dominion - Columbia II	Photovoltaic	11.1 MW	12/22/2034	2,314
GlidePath Power Solutions - GPS Cabazon Wind LLC	Wind	39.0 MW	1/1/2025	4,299
Capital Dynamics - Kingbird Solar B, LLC	Photovoltaic	14.0 MW	12/31/2036	2,867
FTP Solar				
sPower - Summer Solar	Photovoltaic	10.0 MW	12/31/2041	1,748
sPower - Antelope Big Sky Ranch	Photovoltaic	10.0 MW	12/31/2041	1,748
sPower - Antelope DSR 1 Solar	Photovoltaic	25.0 MW	12/19/2036	3,826
Capital Dynamics - Tequesquite Landfill Solar	Photovoltaic	7.3 MW	12/31/2040	1,341
American Renewable Power-Loyalton	Biomass	0.8 MW	4/19/2023	615
CalEnergy - Salton Sea Portfolio Phase 1	Geothermal	20.0 MW	12/31/2039	12,187
Total		210.5 MW		$ 66,175

[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.

Long-term renewable PPAs with expected delivery:

Supplier	Type	Maximum Contract [1]	Expected Delivery	Energy Delivery No Later No Later	Contract Term In Years
CalEnergy - Salton Sea Portfolio Phase 2	Geothermal	20.0 MW	1/1/2019	1/1/2019	21
CalEnergy - Salton Sea Portfolio Phase 3	Geothermal	46.0 MW	6/1/2020	6/1/2020	20
Total		66.0 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 which increases 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 has been 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 substantial lower pricing under the new PPA. The cost increase under the Salton Sea PPA is approximately $2,500 per year for the agreement's remaining term. As of June 30, 2018 and 2017, the Electric Utility's prepayment of future contractual obligations was $11,131 and $8,927, 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, 2018 and 2017, the Electric Utility has recorded $141 and $118, respectively, in amortization related to the unamortized purchased power.

On January 28, 2003, the Electric Utility entered into a 15-year renewable PPA with Wintec Energy, Ltd (Wintec) to purchase all of the energy output generated by Wintec's wind powered electric generating units with capacity up to 5 MW. Due to unforeseen circumstances, Wintec was only able to generate capacity totaling 1.3 MW. On November 15, 2005, the City Council approved an amendment to the original agreement, reducing the capacity to 1.3 MW. The amended contract with Wintec will terminate in December 2018.

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 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.

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.

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.

On September 19, 2013, the Electric Utility entered into a 20-year PSAs with SCPPA for an 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 Projects, with a nameplate capacity of 15 MW.

NOTE 10. COMMITMENTS (CONTINUED)

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.

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 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.

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 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 commercially operational on December 20, 2016. The Electric Utility's share of Antelope DSR Solar is expected to generate approximately 71,000 MWh of renewable energy per year with an all-in price for energy, capacity and environmental attributes of $53.75 per MWh over the term of the agreement.

On November 16, 2017, the Electric Utility entered into a 5-year PSA with SCPPA for 0.8 MW of biomass energy generated by American Renewable Power (ARP) - Loyalton Biomass Project. The Electric Utility has a 4.48% share of the output of the project through SCPPA, along with Imperial Irrigation District, Modesto Irrigation District, Sacramento Municipal Utility District, and Turlock Irrigation District, has an 18 MW PPA with ARP-Loyalton. The project became commercially operational on April 20, 2018. The Electric Utility's share of ARP Loyalton is expected to generate 6,358 MWh of renewable energy per year with an all-in price for energy, capacity and environmental attributes of $97.50 per MWh over the term of the agreement.

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. 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.

NOTE 10. COMMITMENTS (CONTINUED)

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, 2018 and 2017, the Electric Utility received $8,131 and $6,881, 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 $16,093 and $16,123 as of June 30, 2018 and 2017, 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 $1,097 and $1,097 as of June 30, 2018 and 2017, respectively, and is recorded as inventory in the Statements of Net Position.

CONSTRUCTION COMMITMENTS

As of June 30, 2018, the Electric Utility had major commitments (encumbrances) of approximately $16,322 with respect to unfinished capital projects, of which $1,385 is expected to be funded by restricted cash reserves and $14,937 to be funded by unrestricted cash reserves.

FORWARD PURCHASE/SALE AGREEMENTS

In order to meet summer peaking requirements, the Electric Utility may contract on a monthly or quarterly basis, for the purchase or sale of natural gas, electricity and/or capacity products on a short term horizon. As of June 30, 2018, the Electric Utility has net commitments for fiscal year 2019 and thereafter, of approximately $5,897, with a market value of $7,506.

NOTE 11. 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 7.

OLQUIN LAWSUIT

On April 28, 2016, a writ of mandate lawsuit entitled *Richard Olquin v. City of Riverside* was filed against the City asserting that adding certain funds received by the Electric Utility from the CAISO to the Electric revenue transfer to the City's general fund was a violation of Proposition 26. Plaintiff sought a court order compelling the City to return to the Electric Utility approximately $115 million, which represents all Electric revenue transfer paid to the City's general fund since May 1, 2013, as well as a permanent injunction prohibiting future Electric revenue transfers.

In April of 2017, the trial court entered judgment in favor of the City, on the grounds that (1) Olquin had failed to allege a rate increase, because the contested transfer did not require the Electric Utility to raise its rates; and (2) even if such a rate increase could be alleged, Olquin's lawsuit was untimely under the statute of limitations in Public Utilities Code Section 10004.5. Mr. Olquin subsequently passed away and Alysia Webb substituted in as plaintiff. In May of 2017, Olquin/Webb filed an appeal to that judgment. On May 4, 2018, the appellate court ruled in favor of the City in a published decision, *Alysia Webb v. City of Riverside*

NOTE 11. LITIGATION (CONTINUED)

(2018) 23 Cal.App.5th 244. No appeal has been filed to that decision, and the time within which to file the appeal has expired.

NOTE 12. PRIOR PERIOD ADJUSTMENTS

A prior period adjustment of ($328) was made to decrease the Electric Utility's, including Public Benefits, net position. The OPEB payable of $7,905 in 2017 was eliminated due to the implementation of GASB 75. The payable was the cumulative difference between annual OPEB costs and the Electric's contribution. The adjustment was made to reflect the prior period costs related to other post-employment benefits. The restatement of beginning net position is as follows:

Net position at July 1, 2017, as previously stated	$	484,201
Other post-employment benefits adjustment		(328)
Net position at July 1, 2017, as restated	$	483,873

ELECTRIC UTILITY:
KEY HISTORICAL OPERATING DATA

FISCAL YEAR	2017/18	2016/17[4]	2015/16	2014/15	2013/14
POWER SUPPLY MEGAWATT-HOURS (MWH)					
Nuclear					
Palo Verde	102,900	102,400	103,300	103,900	99,900
Coal					
Intermountain Power	627,100	619,500	560,000	744,200	802,100
Hoover (Hydro)	29,000	28,400	30,900	30,900	33,200
Gas					
Springs	700	500	500	950	1,300
RERC	89,600	84,300	51,600	39,500	64,400
Clearwater	24,200	25,900	15,500	16,100	20,600
Renewable Resources	798,200	678,000	585,800	397,000	423,800
Market Purchases	633,500	770,500	1,084,700	1,029,350	899,200
Exchanges In	0	0	28,600	87,000	93,300
Exchanges Out	0	0	(133,500)	(131,800)	(158,300)
Total	2,305,200	2,309,500	2,327,400	2,317,100	2,279,500
System peak megawatt (MW)	640.3	581.7	598.6	604.4	577.92
ELECTRIC USE					
Number of meters as of year end					
Residential[1]	97,531	97,372	96,934	96,664	96,820
Commercial	11,181	11,016	10,898	10,757	10,558
Industrial	854	833	891	888	898
Other[2]	53	53	53	79	82
Total	109,619	109,274	108,776	108,388	108,358
Millions of kilowatt-hours (kWh) sales					
Residential	727	730	726	711	700
Commercial	447	448	438	428	421
Industrial	999	996	982	995	997
Other	22	23	23	31	30
Subtotal	2,195	2,197	2,169	2,165	2,148
Wholesale[3]	0	1	0	2	4
Total	2,195	2,198	2,169	2,167	2,152

[1]Decrease in meters, as adjusted in fiscal year 14/15, was most likely due to timing of billing customers. A new billing system was implemented in the fiscal year.

[2]Decrease in Other meters in fiscal year 15/16 was a result of customers transitioning to Commercial and Industrial classes.

[3]For fiscal year 15/16 and 17/18, wholesale kWh was less than 1 millon kWh.

[4]Adjustment of Power Supply megawatt-hours in fiscal year 16/17.

ELECTRIC FACTS	2017/18	2016/17	2015/16	2014/15	2013/14
Average annual kWh per residential customer	7,455	7,519	7,528	7,334	7,239
Average price (cents/kWh) per residential customer	$15.91	$16.12	$16.12	$16.05	$16.00
Debt service coverage ratio (DSC)[5,6]	2.71	2.95	2.87	2.32	2.16
Operating income as a percent of operating revenues	15.3%	20.2%	20.2%	18.0%	19.5%
Employees[7]	489	472	465	465	463

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

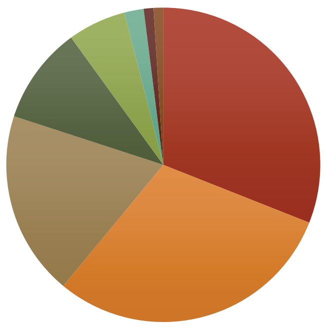
[6]Does not include GASB 68 - Accounting and Financial Reporting for Pension non-cash adjustments of $9,056, ($248), ($5,036), and ($2,594) for fiscal years 17/18 through FY 14/15, respectively.

[7]Approved positions.

WATER ENERGY LIFE
CITY OF RIVERSIDE PUBLIC UTILITIES

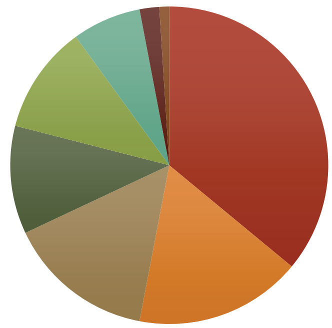
2017/2018 ELECTRIC REVENUE AND RESOURCES

SOURCE OF REVENUE



- Industrial Sales 31¢
- Residential Sales 30¢
- Commercial Sales 19¢
- Transmission Revenue 10¢
- Other Revenue 6¢
- Public Benefit Programs 2¢
- Other Sales 1¢
- Investment Income 1¢
- Wholesale Sales (less than 1¢)

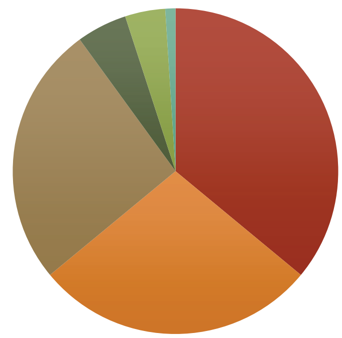
DISTRIBUTION OF REVENUE



- Production 36¢
- Transmission 17¢
- Distribution 15¢
- Debt Service 11¢
- Transfers to the City's General Fund* 11¢
- Additions & Replacements to the System 7¢
- Public Benefit Programs 2¢
- Unamortized Purchased Power 1¢
- Additional Reserves (less than 1¢)

*Based on transfer of 11.5% of fiscal year 2016/2017 gross operating revenues including adjustments.

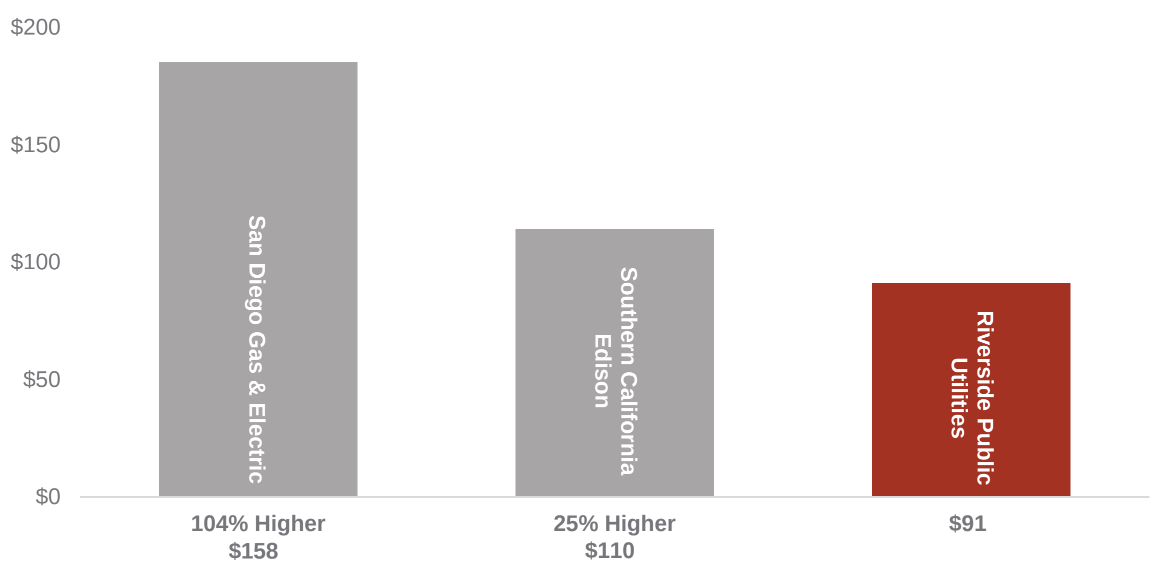
ENERGY RESOURCES*



- Renewables 36%
- Market Purchases 28%
- Coal 26%
- Nuclear 5%
- Gas 4%
- Hydropower 1%

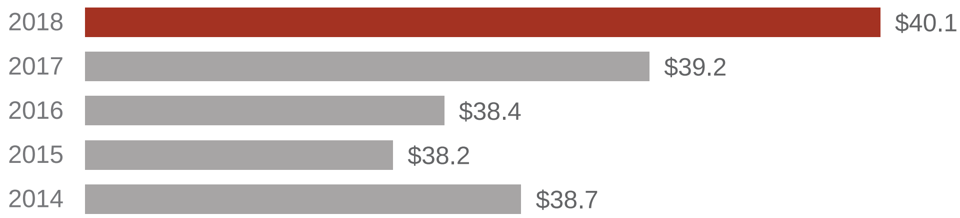
*Energy Resources are based on calendar year 2017 as filed with the California Energy Commission

ELECTRIC RATE COMPARISON - 592 KWH PER MONTH (AS OF JUNE 30, 2018)

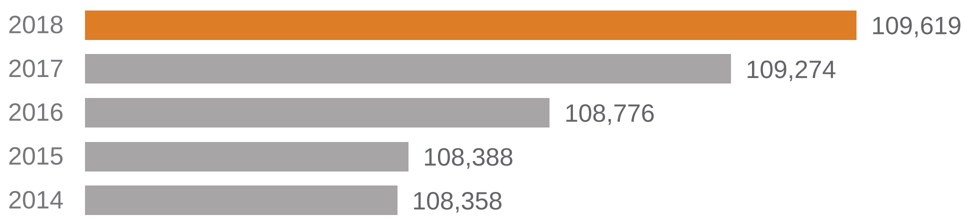


ELECTRIC KEY OPERATING INDICATORS

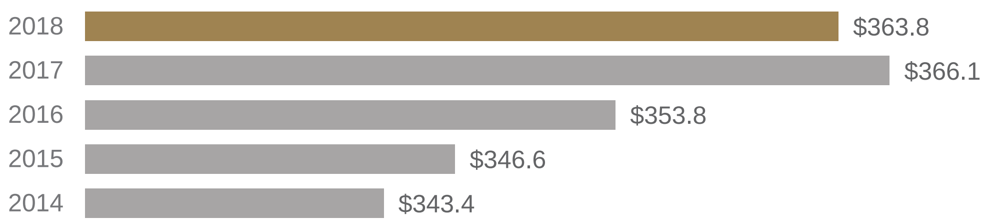
General Fund Transfer (In Millions)



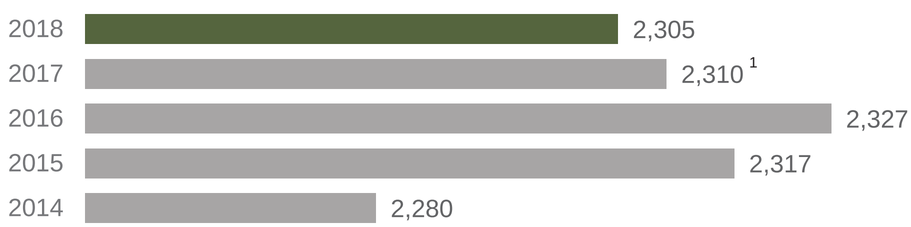
Number of Meters At Year End



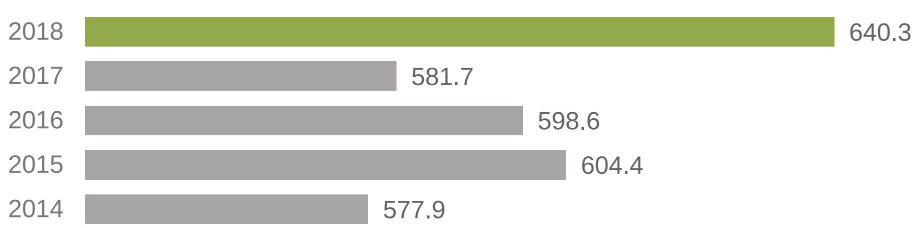
Total Operating Revenue (In Millions)



Production (In Million Kilowatt-Hours)



Peak Day Demand (In Megawatts)



[1] Adjustment of Power Supply megawatt-hours in fiscal year 16/17.

ELECTRIC FACTS AND SYSTEM DATA

Established 1895

Service Area Population 325,801

City Service Area Size (square miles) 81.5

System Data

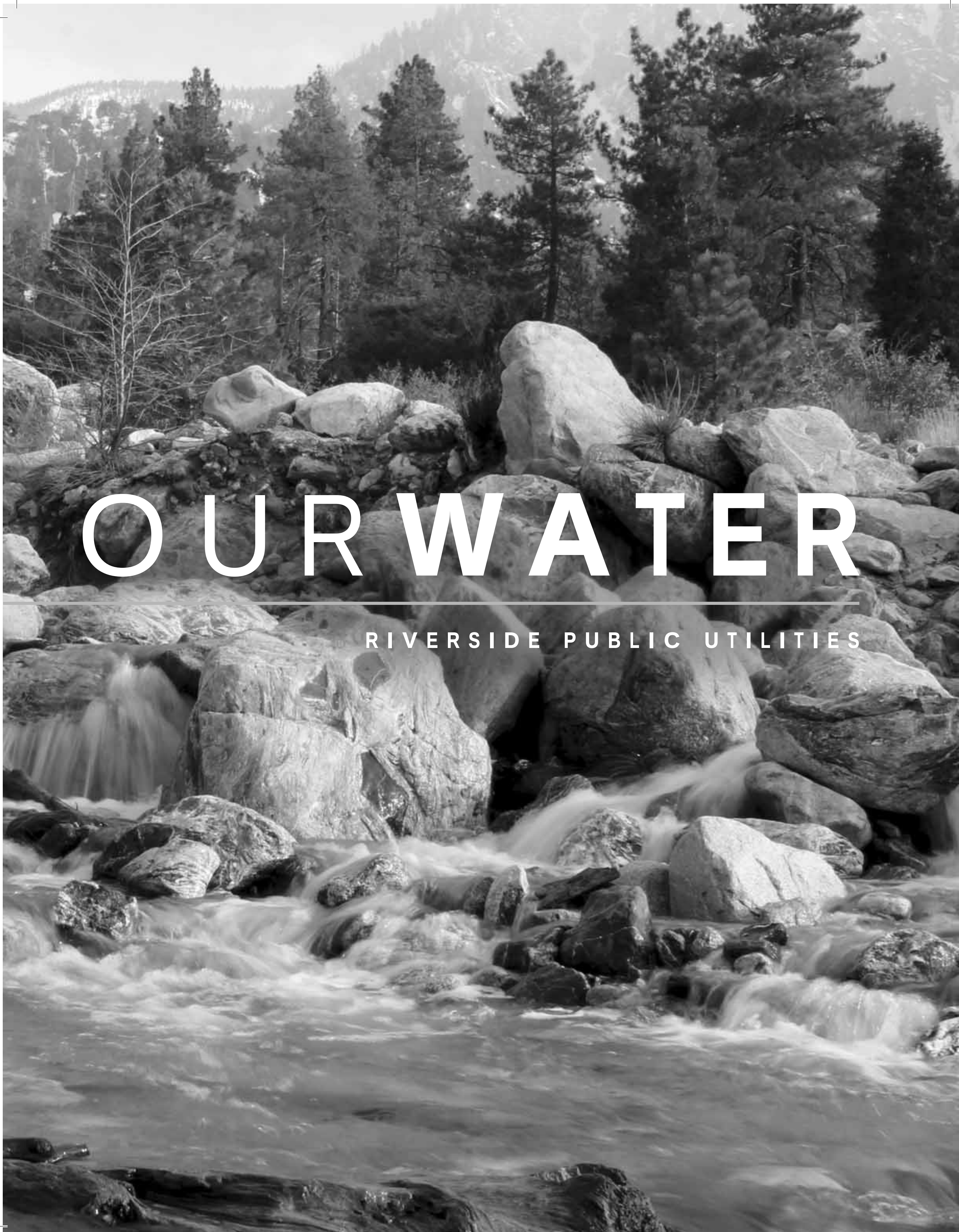
- Transmission Lines (circuit miles) 99.2
- Distribution Lines (circuit miles) 1,345
- Number of Substations 14
- 2017-18 Peak Day (megawatts) 640
  - Highest Single Hourly Use:
    08/31/2017, 3pm, 89.9 degrees
- Historical Peak (megawatts) 640
  - Highest Single Hourly Use:
    08/31/2017, 3pm, 89.9 degrees

Bond Ratings

- Fitch Ratings .... AA-
- Standard & Poor's .... AA-

OUR WATER

RIVERSIDE PUBLIC UTILITIES



MGO Certified Public Accountants

Independent Auditor's Report

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

We have audited the accompanying financial statements of the Water Utility Enterprise Fund (Water Utility) of the City of Riverside, California, (the City), as of and for the years ended June 2018 and 2017, and the related notes to the financial statements, as listed in the table of contents.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with accounting principles generally accepted in the United States of America; this includes 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.

Auditor's Responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements 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 entity's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Water Utility of the City, as of June 30, 2018 and 2017, and the changes in financial position and cash flows thereof for the years then ended in accordance with accounting principles generally accepted in the United States of America.

Emphasis of 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 as of June 30, 2018 and 2017, the changes in its financial position, or, where applicable, its cash flows for the years 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.

Other Matters

Required Supplementary Information

Accounting principles generally accepted in the United States of America require that the management's discussion and analysis, as listed in the table of contents, be presented to supplement the financial statements. Such information, although not a part of the financial statements, is required by the Governmental Accounting Standards Board who considers it to be an essential part of financial reporting for placing the financial statements in an appropriate operational, economic, or historical context. We have applied certain limited procedures to the required supplementary information in accordance with auditing standards generally accepted in the United States of America, which consisted of inquiries of management about the methods of preparing the information and comparing the information for consistency with management's responses to our inquiries, the financial statements, and other knowledge we obtained during our audit of the financial statements. We do not express an opinion or provide any assurance on the information because the limited procedures do not provide us with sufficient evidence to express an opinion or provide any assurance.

Other Information

Our audit was conducted for the purpose of forming an opinion on the financial statements as a whole. The accompanying supplementary Water Utility information is presented for the purposes of additional analysis and are not a required part of the financial statements. Such information has not been subjected to the auditing procedures applied in the audit of the financial statements, and accordingly, we do not express an opinion or provide any assurance on it.

Macias Gini & O'Connell LLP

Newport Beach, California
October 31, 2018

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 2017-18 financial report for the period ended June 30, 2018 and 2017 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 89 of this report. All amounts, unless otherwise indicated, are expressed in thousands of dollars.

FINANCIAL HIGHLIGHTS

- During the fiscal year ended June 30, 2018, the Water Utility implemented Governmental Accounting Standards Board Statement No. 75 (GASB 75), *Accounting and Financial Reporting for Postemployment Benefits other than Pensions* – a replacement of GASB Statements No. 45 as amended, and No. 57, and establishes new accounting and financial reporting requirements for Other Post-Employment Benefits (OPEB) plans. As of July 1, 2017, the Water Utility restated beginning net position in the amount of $125 to record adjustments to the OPEB liability. For more information, refer to the OPEB section below, Note 6 of the accompanying financial statements. The Water Utility did not restate the financial statements for the fiscal years ended June 30, 2017 and 2016 because the necessary actuarial information was not provided for the prior years presented.

- 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 $3,149 and ($85) in June 30, 2018 and 2017, respectively.

- Retail sales, net of uncollectibles/recovery, were $58,216 and $54,596 for the fiscal years ended June 30, 2018 and 2017, respectively. The increase in sales was primarily due to continued increase in consumption as a result of the lifting of water conservation mandates.

- Utility plant assets as of June 30, 2018 increased by $18,492 due to continued investment in water infrastructure system to provide safe, reliable water to Water Utility's customers.

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 "Comprehensive Annual Financial Report."

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 historical sales, operating activities and other relevant data.

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 89 to 114 of this report.

WATER UTILITY FINANCIAL ANALYSIS

CONDENSED STATEMENTS OF NET POSITION

	2018	2017	2016
Current and other assets	$ 67,740	$ 84,801	$ 92,456
Capital assets	486,465	467,973	463,149
Deferred outflows of resources	23,338	24,097	24,023
Total assets and deferred outflows of resources	577,543	576,871	579,628
Long-term debt outstanding	182,814	189,492	195,562
Other liabilities	86,181	75,340	70,075
Deferred inflows of resources	3,470	6,621	8,779
Total liabilities and deferred inflows of resources	272,465	271,453	274,416
Net investment in capital assets	291,562	271,087	260,468
Restricted	8,167	8,079	8,175
Unrestricted	5,349	26,252	36,569
Total net position	$ 305,078 [(1)]	$ 305,418	$ 305,212

[(1)] Restated July 1, 2017, see Note 10 of the financial statements.

ASSETS AND DEFERRED OUTFLOWS OF RESOURCES

2018 compared to 2017 The Water Utility’s total assets and deferred outflows of resources were $577,543, reflecting an increase of $672 (0.1%) primarily due to the following:

- Current and other assets, comprised of restricted and unrestricted assets, decreased by $17,061. This change reflects a decrease of $16,039 in unrestricted cash and cash equivalent for the use of reserves to fund on-going capital projects and a decrease of $1,220 in accounts receivable.
- Capital assets increased by $18,492 primarily due to an increase of $9,996 in construction in progress and an increase of $8,496 for completed transmission and distribution system assets, net of current year depreciation. Additional capital asset information can be found in the “Capital Assets and Debt Administration” section.
- Deferred outflows of resources decreased by $759 primarily due to a decrease of $2,661 in deferred outflows of related to pension for contributions made in the current year subsequent to the measurement date of the net pension liability and the difference between project and actual earnings on pension plan investments, a decrease of $2,012 in deferred changes in derivative values, and an amortization of loss on refunding of $511. These decreases are offset by an increase in deferred ouflows related to note payable of $4,425.

2017 compared to 2016 Total assets and deferred outflows of resources were $576,871, reflecting a decrease of $2,757 (0.5%) over prior year. Current and other assets decreased by $7,655 due to the decrease of $10,038 in unrestricted cash and cash equivalent for the use of reserves to fund on-going capital projects offset by an increase of $2,421 in restricted cash and cash equivalent for the financing proceeds received for the lease purchase of heavy equipment vehicles. Capital assets increased by $4,824 primarily due to an increase of $7,318 in construction in progress offset by a decreased of $2,494 for current year depreciation, net of completed transmission and distribution system assets.

LIABILITIES AND DEFERRED INFLOWS OF RESOURCES

2018 compared to 2017 The Water Utility's total liabilities and deferred inflows of resources were $272,465, an increase of $1,012 (0.4%) primarily due to the following:

- Long-term debt outstanding decreased by $6,678 primarily due to principal payments on revenue and pension obligation bonds.
- Other liabilities increased by $10,841 primarily due to an increase $7,760 in note payable, an increase of $4,415 in net pension liability, and an increase of $1,121 in accounts payable and other accruals. These increases were partially offset by a decrease of $2,600 in the negative fair value of derivative instruments. Additional information on note payable can be found in Note 4 of the accompanying financial statements.
- Deferred inflows of resources decreased by $3,151 primarily due to a decrease in deferred inflows related pension, 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.

2017 compared to 2016 Total liabilities and deferred inflows of resources were $271,453, reflecting a decrease of $2,963 (1.1%). The decrease was primarily due to a decrease of $6,070 in long-term debt outstanding primarily due to principal payments on revenue and pension obligation bonds. There was an increase in other liabilities of $5,265 primarily due to an increase of $6,208 in the net pension liability, an increase of $2,095 in capital lease payable, and an increase of $738 in accounts payable and other accruals. These increases were offset by a decrease of $4,205 in the negative fair value of derivative instruments. Deferred inflows of resources decreased by $2,158 due to a decrease in deferred inflows related to pension.

NET POSITION

2018 compared to 2017 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, totaled $305,078, a decrease of $340 (0.1%).

- The largest portion of the Water Utility's total net position, which is its investment in capital assets of $291,562 (95.6%), had an increase of $20,475 from prior year. Investment in capital assets reflects the Water Utility's investment in treatment, pumping, source of supply, transmission and distribution facilities, less any related outstanding debt used to acquire these assets. Additional capital asset information can be found in the "Capital Assets and Debt Administration" section.
- The restricted portion of net position totaled $8,167 (2.7%), reflecting a slight increase from prior year. Restricted net position is subject to external restrictions on its use and is reserved for items such as debt repayment and funds collected for Water Conservation Programs.
- The unrestricted portion of net position totaled $5,349 (1.7%), a decrease of $20,903 (79.6%) from prior year, primarily attributable to the use of unrestricted cash and cash equivalent to fund capital projects. Unrestricted net position may be used to meet the Water Utility's ongoing operational needs and obligations to customers and creditors.

2017 compared to 2016 Total net position increased by $206 (0.1%) to $305,418. The increase was primarily due to the increase of $10,619 in net investment in capital assets. This was offset by a decrease of $10,317 in the unrestricted portion of net position mainly resulting from the use of unrestricted cash and cash equivalent to fund capital projects.

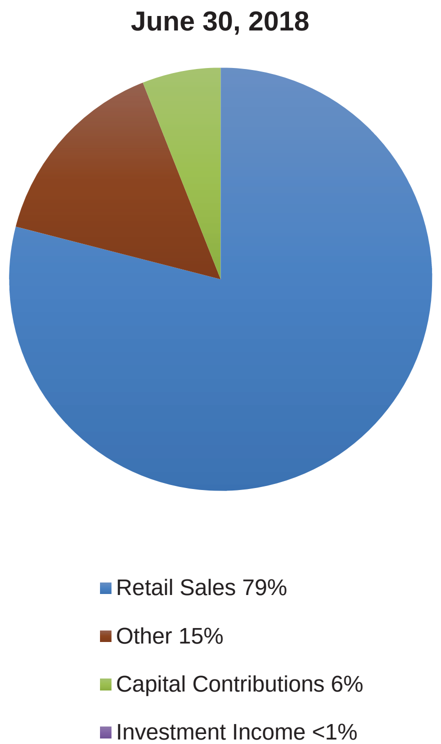
WATER UTILITY FINANCIAL ANALYSIS (CONTINUED)

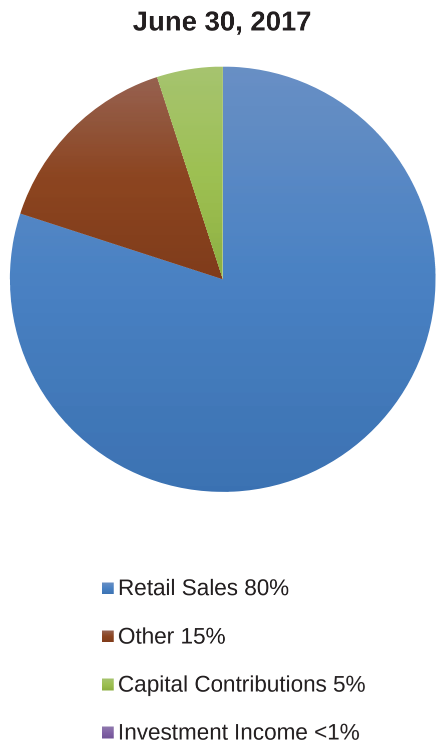
CONDENSED STATEMENTS OF CHANGES IN NET POSITION

	2018	2017	2016
Revenues:			
Retail sales, net	$ 58,216	$ 54,596	$ 50,195
Other revenues	11,463	9,930	8,861
Investment income	250	17	1,075
Capital contributions	4,181	3,525	3,133
Total revenues	74,110	68,068	63,264
Expenses:			
Operations and maintenance	38,976	34,070	31,115
Purchased energy	5,827	5,136	4,664
Depreciation	14,914	14,320	13,510
Interest expenses and fiscal charges	8,435	8,663	8,352
Total expenses	68,152	62,189	57,641
Transfers:			
Transfers in from the City's general fund	-	-	3,333
Transfers to the City's general fund	(6,173)	(5,673)	(6,430)
Total transfers	(6,173)	(5,673)	(3,097)
Changes in net position	(215)	206	2,526
Net position, July 1, as previously reported	305,418	305,212	302,686
Less: Cumulative effect of change in accounting principle [1]	(125)	-	-
Net position, July 1, as restated	305,293	305,212	302,686
Net position, June 30	$ 305,078	$ 305,418	$ 305,212

[1] For the implementation of postemployment benefits other than pensions, GASB No. 75.

REVENUES BY SOURCES





2018 compared to 2017 The Water Utility's total revenues of $74,110 increased by $6,042 (8.9%) primarily due to the following changes:

- Retail sales (residential, commercial, industrial, and others), net of uncollectibles/recovery, totaled $58,216, an increase of $3,620 (6.6%) from prior fiscal year. Retail sales continue to be the primary revenue source for the Water Utility. The increase was due to a 9.7% increase in consumption representing continuing increases in retail sales as result of the lifting water conservation mandates.

- Other revenues of $11,463 increased by $1,533 (15.4%) due to an increase of water conveyance revenue from new contracts and liquidated damages from construction delays on certain water well projects.

- Capital contribution of $4,181 increased by $656 (18.6%) primarily from non-cash contribution for donated assets received.

2017 compared to 2016 Total revenues of $68,068, excluding transfers in, increased by $4,804 (7.6%) primarily due to the following changes:

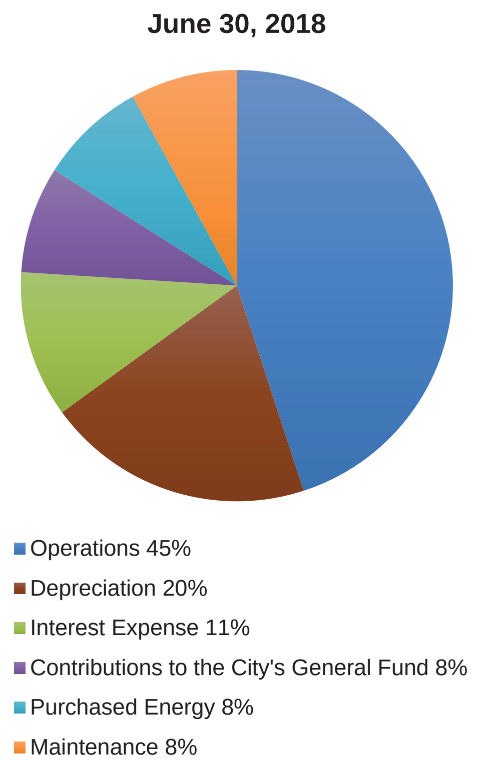
- Retail sales (residential, commercial, industrial, and others), net of uncollectibles/recovery, totaled $54,596, an increase of $4,401 (8.8%) from prior fiscal year. The increase was primarily due to an 8.4% increase in retail consumption as a result of the lifting of water conservation mandates.

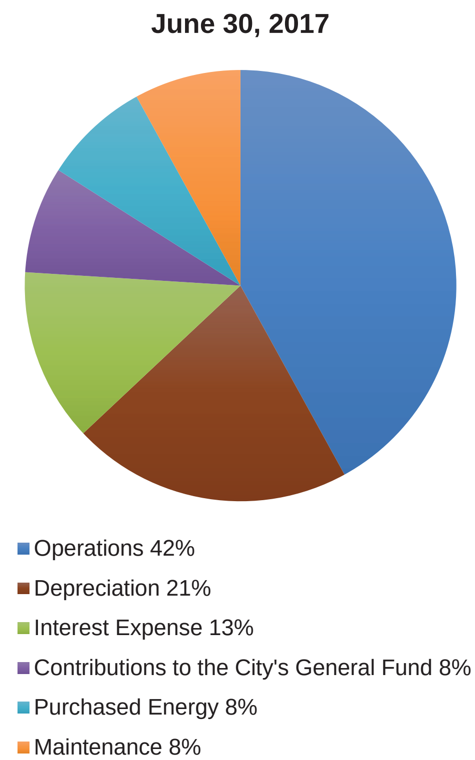
- Other revenues of $9,930 increased by $1,069 (12.1%) primarily due to an increase water conveyance revenue due to new contracts and an increase in wholesale water sales.

WATER UTILITY FINANCIAL ANALYSIS (CONTINUED)

- Investment income of $17 decreased by $1,058 (98.4%) due to a decrease in the market value of investments and lower cash balances from the use of reserves to fund capital projects.

EXPENSES BY SOURCES





2018 compared to 2017 The Water Utility's total expenses, excluding general fund transfer, were $68,152, an increase of $5,963 (9.6%). The increase was mainly due to non-cash pension expense adjustment of $3,149 as a result of pension accounting standards, an increase in production costs resulting from higher consumption and an increase in general operations and maintenance costs.

2017 compared to 2016 Total expenses, excluding general fund transfer, were $62,189, an increase of $4,584 (7.9%). The increase was mainly due to a prior year non-cash pension expense credit of $1,806 as a result of pension accounting standards, an increase in production costs resulting from higher consumption and an increase in general operations and maintenance costs.

TRANSFERS

Pursuant to the City's Charter, 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 $6,173 and $5,673 for 2018 and 2017, respectively to the City's general fund. This represents a $500 increase from prior fiscal year due to an increase in retail sales as a result of an increase in consumption.

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, and construction in progress, 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:

	2018	2017	2016
Source of supply	$ 46,565	$ 45,671	$ 46,355
Pumping	19,690	19,814	20,197
Treatment	30,683	30,679	31,746
Transmission and distribution	328,656	320,660	323,027
General	2,664	3,145	1,852
Land	20,840	20,484	20,484
Intangible	13,398	13,547	12,833
Construction in progress	23,969	13,973	6,655
Total capital assets	$ 486,465	$ 467,973	$ 463,149

2018 compared to 2017 The Water Utility's investment in capital assets, net of accumulated depreciation, is $486,465 an increase of $18,492 (4.0%). The increase resulted mainly from the following significant capital projects, offset by current year depreciation:

- $10,813 for continued pipeline replacement programs.
- $7,049 for recycled water facilities and site conversions.
- $3,742 for system expansion and improvements, transmission mains replacement, and meter replacements.
- $3,685 for facilities rehabilitation including pump stations, booster stations, and wells.

2017 compared to 2016 Investment in capital assets, net of accumulated depreciation, increased by $4,824 (1.0%) to $467,973. Major capital projects included $6,804 for system expansion and improvements, meter replacements, and facilities rehabilitation and $10,041 for continued pipeline replacement programs.

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

CAPITAL ASSETS AND DEBT ADMINISTRATION (CONTINUED)

DEBT ADMINISTRATION

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

	2018	2017	2016
Revenue bonds	$ 182,885	$ 188,300	$ 193,480
Unamortized bond premium	1,749	2,064	2,442
Pension obligation bonds	3,756	4,439	4,338
Contracts payable	937	937	938
Less: Current portion of revenue and pension obligation bonds	(6,513)	(6,248)	(5,636)
Total	$ 182,814	$ 189,492	$ 195,562

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 2.14, 2.04, and 1.80 at June 30, 2018, 2017, and 2016, respectively. The debt is backed by the revenues of the Water Utility. The prior years' debt service coverage ratio has been restated to exclude the non-cash pension related adjustment for required pension accounting standards. For additional information, see Note 4 of the accompanying financial statements and the Key Historical Operating Data section.

The Water Utility's long-term debt decreased by $6,678 (3.5%) and $6,070 (3.1%) for 2018 and 2017, respectively primarily due to principal payments.

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 “AAA”, “AA+” and “Aa2” from Standard & Poor's (S&P), Fitch Ratings (Fitch) and Moody's, respectively.

In January 2017, S&P assigned its “AAA” long-term rating on the 2011A Variable Rate Water Refunding Revenue Bonds and affirmed the “AAA” long-term rating on the existing Water revenue bonds.

In March 2017, Fitch affirmed its “AA+” long-term rating on the Water Utility's outstanding revenue bonds.

In July 2018, Moody's affirmed its “Aa2” long-term rating on the Water Utility's outstanding revenue bonds.

These affirmations and ratings reflect the Water Utility's strong financial performance, advantageous water supply, investments in infrastructure and rate competitiveness, among many other factors. The Water Utility has maintained these credit ratings since 2011.

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 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; however, the aquifers the Water Utility draws from are experiencing historic low levels. The Water Utility has responded by continuing to offer a wide variety of water conservation programs for its customers in an effort to conserve its water resources.

The Water Utility continues to offer customers a wide variety of water conservation programs that help reduce their water usage and utility costs, 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 residents 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.

In addition, the Water Utility creates marketing campaigns to promote efficient water use and management for residents and businesses. These campaigns provide resources to explore water rebates, information on water quality, water efficiency tips and resources to assist individuals to create a water-efficient property.

The Water Utility's water conservation and efficiency programs have assisted the residents and business to save 42,000,000 gallons of water for the period of July 2017 and June 2018.

The Water Utility's long range water supply planning includes significant contributions of both conservation and recycled water. 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.

WATER CONSERVATOIN

On November 10, 2009, the Governor signed SBX7-7, which requires the State of California to achieve a (i) 10% reduction in urban per capita water use by December 31, 2015, and (ii) 20% reduction in urban per capita water use by December 31, 2020. Additionally, in May 31, 2018, the Governor signed long-term water-use efficiency bills AB 1668 and SB 606 into law to provide standards for indoor residential water use of 55 gallons per capita per day (GPCD) until 2025, 52.5 GPCD from 2025 to 2030, and 50 GPCD beginning in 2030.

The City established its urban water use targets for 2015 and 2020, respectively, in accordance with the above law and bills. The 2015 and 2020 urban water use targets for the Water System's service area were recalculated in the 2015 Urban Water Management Plan to reflect the use of DWR Population Tool. They are 239 GPCD and 213 GPCD, respectively. The City intends to meet the conservation requirements of SBX7-7, AB 1668, and SB 606 through increased use of recycled water and implementation of additional conservation measures.

WATER STANDARDS

The development of new and increasingly stringent drinking water regulations by the California Environmental Protection Agency (CalEPA) and 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.

In 2011, the United States Environmental Protection Agency ("**USEPA**") announced plans to establish a federal drinking water standard for perchlorate. The timetable for completion of a federal Maximum Contaminant Level ("MCL") for perchlorate is unknown. Presently USEPA is requesting peer review of its draft Biologically Based Dose-Response Model to develop a perchlorate MCL goal. Once a MCL goal is established the USEPA will began the process of developing an MCL. The State of California MCL for perchlorate is 6 parts per billion ("ppb"). The MCL may be considered for possible revision as a result of the California Environmental Protection Agency's 2015 reduction in the perchlorate Public Health Goal from 6 ppb to 1 ppb. In addition, the California State Division of Drinking Water is currently evaluating lowering the perchlorate detection limit for reporting purposes from 4 pbb to as low as 0.5 ppb. A reduction in the perchlorate standard will impact the Water Utility's water supply costs.

In December 2016, the USEPA completed its third review of existing National Primary Drinking Water Regulations (NPDWR) (i.e., the Six-Year Review 3). The USEPA determined that 68 of the 76 NPDWR remain appropriate (i.e., do not need to be revised) and that eight NPDWRs are candidates for regulatory revision. These eight NPDWRs are included in the Stage 1 and the Stage 2 Disinfectants and Disinfection Byproducts Rules, the Surface Water Treatment Rule, the Interim Enhanced Surface Water Treatment Rule and the Long Term 1 Enhanced Surface Water Treatment Rule. The eight NPDWRs are chlorite, Cryptosporidium, Giardia lamblia, haloacetic acids (HAA5), heterotrophic bacteria, Legionella, total trihalomethanes (TTHM) and viruses. Any revision resulting in the lower of these standards may impact the Water Utility's water supply costs.

On December 14, 2017, the State Water Resources Control Board adopted an MCL for 1,2,3-Trichloropropane ("1,2,3-TCP) of 0.000005 mg/L or 5 parts per trillion (ppt). Initial sampling began January 1, 2018, and will be completed by December 31, 2018. To date six of the City's potable wells show detection of 1,2,3-TCP and exceed the MCL. These wells extract water from the same aquifers that are contaminated by other known anthropogenic chemicals and are currently being treated by existing GAC treatment facilities.

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.

CLEAN WATER ACT

On March 25, 2014, USEPA and the Army Corps released a draft proposed rule revising the definition of "Waters of the United States." The proposed rule significantly expanded the scope of Federal jurisdiction in determining the waters of United States. In particular, the rule added jurisdiction over water conveyance systems, groundwater recharge, and recycled water systems. The proposed rule defined tributaries too broadly that it included canals and aqueducts. The inclusion of canals and aqueducts would make the transfer of water much more difficult and would increase permitting costs. The draft rule was made final on August 28, 2015. However on October 9, 2015, the United States Court of Appeals issued a Stay causing the USEPA and the Army Corps to resume using the prior regulations defining the term "Waters of the United States." On February 28, 2017, the President of the United States issued an Executive Order directing the EPA and Department of the Army to review and rescind or revise the 2015 Rule.

The 2015 revised rule would have impacted a water agencies' water recycling and recharge operations. In California, water recycling facilities, groundwater replenishment basins, and aquifer storage facilities are located adjacent to "Waters of the United States." The change of the term "adjacent wetlands" to "adjacent waters" means that these facilities would have been required to obtain multiple Clean Water Act permits and potentially trigger reviews under other federal environmental laws. Water recycling is an important strategy to help mitigate the impacts of a prolonged drought, reduce reliance on the Delta and Colorado

River and help meet the co-equal goals of a thriving economy and healthy environment. The 2015 rule would have made these projects and others more difficult to complete and manage. The Water Utility will remain engaged and will continue to advocate at the federal level for sound environmental policy.

FIVE-YEAR WATER RATE PLAN

On May 22, 2018, the City Council approved a new five-year Water Rate Plan, with rate increases that become effective on July 1, 2018, 2019, 2020, 2021 and 2022 with annual reviews of the adopted rates by City Council. The system average rate increase effective July 1, 2018 is 4.50%, followed by system average rate increases of 5.75% in years two through four, and followed by system average rate increase of 6.50% in the final year of the rate plan. The Water Rate Plan includes a redesign of water rates over a five-year period to better align with its cost of serving customers and its revenue requirement. The water rate restructuring is designed to provide financial stability and correct the imbalance of costs versus revenue recovery by increasing fixed cost recovery through monthly service charges to reflect the nature of underlying costs. Pursuant to City Council direction, the first annual review of rates will be conducted in December of 2019.

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 Assistant General Manager Finance/Administration, Riverside Public Utilities, 3750 University Avenue, 3rd floor, Riverside, CA 92501. Additional financial information can also be obtained by visiting www.RiversidePublicUtilities.com.

WATER UTILITY:
FINANCIAL STATEMENTS

STATEMENTS OF NET POSITION

ASSETS AND DEFERRED OUTFLOWS OF RESOURCES	June 30, 2018	June 30, 2017
	(in thousands)	
UTILITY PLANT:		
Utility plant, net of accumulated depreciation (Note 3)	$ 486,465	$ 467,973
CURRENT ASSETS:		
Unrestricted assets:		
Cash and cash equivalents (Note 2)	47,464	63,503
Accounts receivable, less allowance for doubtful accounts 2018 $194; 2017 $136	8,841	10,061
Accrued interest receivable	191	231
Advances to other funds of the City	131	78
Prepaid expenses	238	164
Total unrestricted current assets	56,865	74,037
Restricted assets:		
Cash and cash equivalents (Note 2)	8,451	8,370
Water Conservation Programs -cash and cash equivalents (Note 2)	2,315	2,283
Water Conservation Programs receivable	109	111
Total restricted current assets	10,875	10,764
Total current assets	67,740	84,801
Total assets	554,205	552,774
DEFERRED OUTFLOWS OF RESOURCES:		
Deferred outflows related to pension (Note 5)	10,881	13,542
Deferred outflows related to note payable	4,425	-
Changes in derivative values	1,869	3,881
Loss on refunding	6,163	6,674
Total deferred outflows of resources	23,338	24,097
Total assets and deferred outflows of resources	$ 577,543	$ 576,871

See accompanying notes to the financial statements

STATEMENTS OF NET POSITION

NET POSITION, LIABILITIES, AND DEFERRED INFLOWS OF RESOURCES	June 30, 2018	June 30, 2017
	(in thousands)	
NET POSITION:		
Net investment in capital assets	$ 291,562	$ 271,087
Restricted for:		
Debt service (Note 7)	6,186	6,068
Water Conservation Programs	1,981	2,011
Unrestricted	5,349	26,252
Total net position	305,078	305,418
LONG-TERM OBLIGATIONS, LESS CURRENT PORTION (Note 4)	182,814	189,492
OTHER NON-CURRENT LIABILITIES:		
Net other postemployment benefits liability (Note 6)	3,410	3,266
Net pension liability (Note 5)	38,880	34,465
Compensated absences (Note 4)	344	288
Derivative instrument (Note 4)	5,593	8,193
Capital lease payable (Note 4)	1,884	2,095
Note payable (Note 4)	20,322	12,927
Total other non-current liabilities	70,433	61,234
CURRENT LIABILITIES PAYABLE FROM RESTRICTED ASSETS:		
Accrued interest payable	1,542	1,619
Water Conservation Programs payable	78	50
Current portion of long-term obligations (Note 4)	6,363	6,098
Total current liabilities payable from restricted assets	7,983	7,767
CURRENT LIABILITIES:		
Accounts payable and other accruals	5,536	4,415
Current portion of long-term obligations (Note 4)	150	150
Unearned revenue	64	185
Customer deposits	813	752
Note payable (Note 4)	1,202	837
Total current liabilities	7,765	6,339
Total liabilities	268,995	264,832
DEFERRED INFLOWS OF RESOURCES:		
Deferred inflows related to pension (Note 5)	2,585	6,510
Deferred inflows related to other postemployment benefits (Note 6)	112	-
Regulatory charges	773	111
Total deferred inflows of resources	3,470	6,621
Total net position, liabilities and deferred inflows of resources	$ 577,543	$ 576,871

See accompanying notes to the financial statements

STATEMENTS OF REVENUES, EXPENSES AND CHANGES IN NET POSITION

	For the Fiscal Year Ended June 30	
	2018	2017
	(in thousands)	
OPERATING REVENUES:		
Residential sales	$ 37,148	$ 34,994
Commercial sales	19,317	17,869
Other sales	1,880	1,764
Water conveyance revenue	5,082	4,385
Water Conservation Programs	886	1,120
Other operating revenue	2,515	2,526
Total operating revenues before uncollectibles	66,828	62,658
Estimated uncollectibles, net of bad debt recovery	(129)	(31)
Total operating revenues, net of uncolectibles	66,699	62,627
OPERATING EXPENSES:		
Operations	32,286	27,298
Maintenance	5,775	5,437
Purchased energy	5,827	5,136
Water Conservation Programs	915	1,335
Depreciation	14,914	14,320
Total operating expenses	59,717	53,526
Operating income	6,982	9,101
NON-OPERATING REVENUES (EXEPNSES):		
Investment income	250	17
Interest expense and fiscal charges	(8,435)	(8,663)
Gain on sale of assets	177	61
Other	2,803	1,838
Total non-operating revenues (expenses)	(5,205)	(6,747)
Income before capital contributions and transfers	1,777	2,354
Capital contributions	4,181	3,525
Transfers out - contributions to the City's general fund	(6,173)	(5,673)
Total capital contributions and transfers	(1,992)	(2,148)
(Decrease)/Increase in net position	(215)	206
NET POSITION, BEGINNING OF YEAR, AS PREVIOUSLY REPORTED	305,418	305,212
LESS: CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE	(125)	-
NET POSITION, BEGINNING OF YEAR, AS RESTATED	305,293	305,212
NET POSITION, END OF YEAR	$ 305,078	$ 305,418

See accompanying notes to the financial statements

STATEMENTS OF CASH FLOWS

	For the Fiscal Year Ended Ended June 30, 2018	2017
	(in thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
Cash received from customers and users	$ 67,434	$ 62,443
Cash paid to suppliers and employees	(40,520)	(38,177)
Other receipts	1,566	794
Net cash provided by operating activities	28,480	25,060
CASH FLOWS FROM NON-CAPITAL FINANCING ACTIVITIES:		
Transfers out - contributions to the City's general fund	(6,173)	(5,673)
Payment on pension obligation bonds	(683)	(306)
Cash (paid) received on advances to other funds of the City	(53)	101
Net cash used for non-capital financing activities	(6,909)	(5,878)
CASH FLOWS FROM CAPITAL AND RELATED FINANCING ACTIVITIES:		
Purchase of utility plant	(27,824)	(18,634)
Proceeds from the sale of utility plant	177	92
Principal paid on long-term obligations	(5,626)	(5,180)
Interest paid on long-term obligations	(8,320)	(8,522)
Proceeds from capital lease payable	-	2,305
Capital contributions	3,806	2,913
Net cash used for capital and related financing activities	(37,787)	(27,026)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Income (Loss) from investments	290	(32)
Net cash provided (used) by investing activities	290	(32)
Net decrease in cash and cash equivalents	(15,926)	(7,876)
CASH AND CASH EQUIVALENTS, BEGINNING OF YEAR **(including $10,653 and $8,491 at June 30, 2017 and June 30, 2016, respectively, reported in restricted accounts)**	74,156	82,032
CASH AND CASH EQUIVALENTS, BEGINNING OF YEAR **(including $10,766 and $10,653 at June 30, 2018 and June 30, 2017 respectively, reported in restricted accounts)**	$ 58,230	$ 74,156
RECONCILIATION OF OPERATING INCOME TO NET CASH PROVIDED BY OPERATING ACTIVITIES:		
Operating income	$ 6,982	$ 9,101
Adjustments to reconcile operating income to net cash provided by operating activities:		
Depreciation	14,914	14,320
Increase (decrease) in allowance for uncollectible accounts	58	(34)
Decrease (increase) in accounts receivable	607	(549)
(Increase) decrease in prepaid expenses	(74)	4
Increase in accounts payable and other accruals	1,121	529
Increase in compensated absences	56	93
(Decrease) increase in unearned revenue	(121)	185
Increase (decrease) in Water Conservation Programs payable	28	(37)
Increase in customer deposits	61	213
Increase in advance from other funds of the City - pension obligation	-	295
Changes in net pension liability and related deferred outflows and inflows of resources	3,151	(88)
Changes in other postemployment benefits liability and related deferred inflows of resources	131	234
Other receipts	1,566	794
Net cash provided by operating activities	$ 28,480	$ 25,060
SCHEDULE OF NON-CASH INVESTING, CAPITAL AND FINANCING ACTIVITIES:		
Capital contributions - capital assets	932	212
Payment on note payable including interest, offset by rent credit	1,237	1,044
Well relocation with note payable	4,100	0

See accompanying notes to the financial statements

WATER UTILITY:
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

Effective July 1, 2017, the accompanying financial statements reflect the implementation of Governmental Accounting Standards Board (GASB) Statement No. 75, *Accounting and Financial Reporting for Postemployment Benefits Other Than Pensions* (GASB 75). The primary objective of this statement is to improve accounting and financial reporting by state and local governments in regards to postemployment benefits other than pensions (OPEB). These improvements provide users of financial statements decision-useful information, support assessments of accountability and interperiod equity, and create additional transparency. GASB 75 accomplishes this by requiring recognition of the entire OPEB liability, a more comprehensive measure of OPEB expense, along with new note disclosures and required supplementary information. For further details, refer to Note 6.

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. Actual results could differ from those estimates.

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

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 $3,227 at June 30, 2018, and $3,329 at June 30, 2017.

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 five thousand dollars and an estimated useful life in excess of one year. Utility plant assets are valued at historical costs or estimated historical cost, if actual historical cost is not available. Costs include labor; materials; interest during construction; 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.

Interest incurred during the construction phase is reflected in the capitalized value of the asset constructed. For fiscal years ended June 30, 2018 and 2017, the Water Utility capitalized net interest costs of $550 and $330, respectively. Total interest expense incurred by the Water Utility was $8,496 and $8,366, respectively.

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

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 lease purchase financing 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 purposes. 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. This surcharge was approved by the City Council and was phased in over a three-year period with a 0.5 percent, 1.0 percent and 1.5 percent surcharge effective June 1, 2004, 2005 and 2006, respectively, to be in effect for services rendered on or after June 1, 2004 through May 31, 2014. On April 22, 2014, the City Council approved continuation of the 1.5 percent surcharge effective for the next ten years. The programs and services offered include conservation, education, and water use efficiency programs; and research, development and demonstration programs to advance science and technology with respect to water conservation. The activity associated with the surcharge 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 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 1 and level 3 inputs.

City-wide information concerning cash and investments as of June 30, 2018, 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 "Comprehensive Annual Financial Report" (CAFR).

CASH AND INVESTMENTS AT FISCAL AGENTS

Cash and investments maintained by fiscal agents, if any, are considered restricted by the Water Utility and are used to fund construction of capital assets.

UNRESTRICTED 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 considered unrestricted assets and represent the portion of unrestricted reserves 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.

Unrestricted designated cash reserve balances as of June 30, 2018 and 2017 were as follows: Property Reserve $5,000 and $17,281, Recycled Water Reserve $2,915 and $9,359, Customer Deposits $621 and $553, and Capital Repair and Replacement Reserve $2,249 and $1,484, respectively. The combined total for these reserves was $10,785 and $28,677 at June 30, 2018 and 2017, 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 other funds of the City have been recorded as a result of agreements between the Water Utility and the City. The balances as of June 30, 2018 and 2017 are $131 and $78, respectively.

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

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 Long-Term Obligations for further discussion related to the Water Utility's interest rate swaps.

BOND PREMIUM/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.

CAPITAL LEASES

In fiscal year ended June 30, 2017, the Water Utility participated in the City's lease purchase financing program for the acquisition of water system heavy vehicles and equipment. The heavy vehicles and equipment lease financing is for a ten-year term of annual payments with an interest rate of 2.36 percent. Gross proceeds of $2,305 were received for the financing. A trailer was purchased for $36 as of fiscal year ended June 30, 2018. It is anticipated that the remaining vehicles and equipment will be purchased in fiscal year ending June 30, 2019.

As of June 30, 2018, the total liability was $2,095, with the current portion included in accounts payable and other accruals. The annual lease payments for the life of the lease are $260 annually through fiscal year ending June 30, 2027. Total outstanding lease payments are $2,338, with $2,095 representing principal and $243 representing interest.

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, 2018 and 2017 was $813 and $752, respectively.

COMPENSATED ABSENCES

The accompanying financial statements include accruals for salaries, fringe benefits and compensated absences due to employees at June 30, 2018 and 2017. 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 $1,851 at June 30, 2018, and $1,682 at June 30, 2017.

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 primarily 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.

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, including the Utility Plant with a 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, 2017, may be found in the notes to the City's financial statements in the City's CAFR.

Although the ultimate amount of losses incurred through June 30, 2017 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 $288 and $284 for the years ended June 30, 2018 and 2017, 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 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 5.

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. In order to improve the financial reporting of these benefits, the Water Utility has implemented GASB 75, which is explained in detail under New Accounting Pronouncements and in Note 6.

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 changes in derivative values, loss on refunding, note payable and deferred outflows related to pension 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 regulatory charges and deferred inflows related to pension 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 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, 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, 2018 and 2017, $6,173 and $5,673, respectively was transferred representing 11.5 percent.

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. 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.

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

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 adopts the Water Utility's budget in June biennially via resolution.

RECLASSIFICATIONS

Certain reclassifications have been made to prior year's financial statements to conform with the current year's presentation. Such reclassifications have no effect on the net position or the changes in net position.

NOTE 2. CASH AND INVESTMENTS

Cash and investments at June 30, 2018 and 2017, consist of the following (in thousands):

	June 30, 2018	June 30, 2017
	Fair Value	
Equity interest in City Treasurer's investment pool	$ 58,230	$ 74,156
Total cash and investments	$ 58,230	$ 74,156

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

	June 30, 2018	June 30, 2017
Unrestricted cash and cash equivalents	$ 47,464	$ 63,503
Restricted cash and cash equivalents	10,766	10,653
Total cash and investments	$ 58,230	$ 74,156

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, 2018 and 2017:

Investment Type	June 30, 2018 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
City Treasurer's investment pool [1]					
Money market funds	$ 13,730	$ -	$ 13,730	$ -	-
Federal agency securities	733	-	733	-	-
US Treasury notes/bonds	27,822	-	27,822	-	-
Corp medium term notes	3,311	-	3,311	-	-
State investment pool	11,951	-	-	-	11,951
Negotiable certificate of deposit	683	-	683	-	-
Total	$ 58,230	$ -	$ 46,279	$ -	$ 11,951

Investment Type	June 30, 2017 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
City Treasurer's investment pool [1]					
Money market funds	$ 11,347	$ -	$ 11,347	$ -	-
Federal agency securities	1,333	-	1,333	-	-
US Treasury notes/bonds	40,837	-	40,837	-	-
Corp medium term notes	2,271	-	2,271	-	-
State investment pool	16,898	-	-	-	16,898
Negotiable certificate of deposit	1,470	-	1,470	-	-
Total	$ 74,156	$ -	$ 57,258	$ -	$ 16,898

[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 CAFR.

NOTE 2. CASH AND INVESTMENTS (CONTINUED)

Cash and investments distribution by maturities as of June 30, 2018 and 2017, are as follows:

		Remaining Maturity (In Months)		
Investment Type	**June 30, 2018 Fair Value**	**12 Months or less**	**13 to 24 Months**	**25 to 60 Months**
City Treasurer's investment pool [1]				
Money market funds	$ 13,730	$ 13,730	$ -	$ -
Federal agency securities	733	-	-	733
US Treasury notes/bonds	27,822	3,759	13,000	11,063
Corp medium term notes	3,311	784	1,374	1,153
State investment pool	11,951	11,951	-	-
Negotiable certificate of deposit	683	412	91	180
Total	$ 58,230	$ 30,636	$ 14,465	$ 13,129

		Remaining Maturity (In Months)		
Investment Type	**June 30, 2017 Fair Value**	**12 Months or less**	**13 to 24 Months**	**25 to 60 Months**
City Treasurer's investment pool [1]				
Money market funds	$ 11,347	$ 11,347	$ -	$ -
Federal agency securities	1,333	1,333	-	-
US Treasury notes/bonds	40,837	6,031	13,043	21,763
Corp medium term notes	2,271	1,149	1,122	-
State investment pool	16,898	16,898	-	-
Negotiable certificate of deposit	1,470	490	588	392
Total	$ 74,156	$ 37,248	$ 14,753	$ 22,155

[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 CAFR.

NOTE 2. CASH AND INVESTMENTS (CONTINUED)

Presented below is the actual rating as of June 30, 2018 and 2017 for each investment type:

Investment Type	June 30, 2018 Fair Value	Rating as of Year End AAA	AA	A	Unrated
City Treasurer's investment pool [1]					
Money market funds	$ 13,730	$ -	$ 13,257	$ 473	$ -
Federal agency securities	733	733	-	-	-
US Treasury notes/bonds	27,822	27,822	-	-	-
Corp medium term notes	3,311	-	3,311	-	-
State investment pool	11,951	-	-	-	11,951
Negotiable certificate of deposit	683	-	-	-	683
Total	$ 58,230	$ 28,555	$ 16,568	$ 473	$ 12,634

Investment Type	June 30, 2017 Fair Value	Rating as of Year End AAA	AA	A	Unrated
City Treasurer's investment pool [1]					
Money market funds	11,347	-	10,677	670	-
Federal agency securities	1,333	1,333	-	-	-
US Treasury notes/bonds	40,837	40,837	-	-	-
Corp medium term notes	2,271	464	1,570	237	-
State investment pool	16,898	-	-	-	16,898
Negotiable certificate of deposit	1,470	-	-	-	1,470
Total	$ 74,156	$ 42,634	$ 12,247	$ 907	$ 18,368

[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 CAFR.

NOTE 3. UTILITY PLANT

The following is a summary of changes in utility plant during the fiscal years ended June 30, 2018 and 2017 (in thousands):

	Balance As of 6/30/2016	Additions	Retirements/ Transfers	Balance As of 6/30/2017	Additions	Retirements/ Transfers	Balance As of 6/30/2018
Source of supply	$ 62,283	777	-	$ 63,060	$ 2,380	$ -	$ 65,440
Pumping	31,745	302	-	32,047	557	-	32,604
Treatment	43,820	119	-	43,939	1,205	(644)	44,500
Transmission and distribution	475,072	7,787	(406)	482,453	18,357	(302)	500,508
General	14,277	1,697	(29)	15,945	61	(88)	15,918
Intangible	2,354	1,174	-	3,528	494	-	4,022
Depreciable utility plant	629,551	11,856	(435)	640,972	23,054	(1,034)	662,992
Less accumulated depreciation							
Source of supply	(15,928)	(1,461)	-	(17,389)	(1,486)	-	(18,875)
Pumping	(11,548)	(685)	-	(12,233)	(681)	-	(12,914)
Treatment	(12,074)	(1,186)	-	(13,260)	(1,201)	644	(13,817)
Transmission and distribution	(152,045)	(10,124)	376	(161,793)	(10,361)	302	(171,852)
General	(12,425)	(404)	29	(12,800)	(542)	88	(13,254)
Intangible	(362)	(460)	-	(822)	(643)	-	(1,465)
Accumulated depreciation	(204,382)	(14,320)	405	(218,297)	(14,914)	1,034	(232,177)
Net depreciable utility plant	425,169	(2,464)	(30)	422,675	8,140	-	430,815
Land	20,484	-	-	20,484	356	-	20,840
Intangible, non-amortizable	10,841	-	-	10,841	-	-	10,841
Construction in progress	6,655	18,773	(11,455)	13,973	32,135	(22,139)	23,969
Nondepreciable utility plant	37,980	18,773	(11,455)	45,298	32,491	(22,139)	55,650
Total utility plant	$ 463,149	$ 16,309	$ (11,485)	$ 467,973	$ 40,631	$ (22,139)	$ 486,465

NOTE 4. LONG-TERM OBLIGATIONS

The following is a summary of changes in long-term obligations during the fiscal years ended June 30, 2018 and 2017 (in thousands):

	Balance As of 6/30/2016	Additions	Reductions	Balance As of 6/30/2017	Additions	Reductions	Balance As of 6/30/2018	Due Within One Year
Revenue bonds	$195,922	$ -	$ (5,558)	$190,364	$ -	$ (5,730)	$ 184,634	$ 5,635
Pension obligation bonds	4,338	407	(306)	4,439		(683)	3,756	728
Water stock acquisition rights	938	-	(1)	937	-	-	937	150
Compensated absences	1,598	1,408	(1,324)	1,682	1,538	(1,369)	1,851	1,507
Note payable	14,566	-	(802)	13,764	8,600	(840)	21,524	1,202
Capital leases	-	2,305	-	2,305		(210)	2,095	211
Total long-term obligations	$217,362	$ 4,120	$ (7,991)	$213,491	$10,138	$ (8,832)	$ 214,797	$ 9,433

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

CONTRACTS PAYABLE

	June 30, 2018	June 30, 2017
Water Stock Acquisitions: Payable to various water companies	$ 937	$ 937
Total contracts payable	937	937
PENSION OBLIGATION BONDS PAYABLE		
$30,000 2005 Taxable Pension Obligation Bonds Series A: fixed rate bonds issued by the City due in annual installments from $630 to $3,860 through June 2020, interest from 3.9 to 4.8 percent. The Water Utility's proportional share of the outstanding debt is 10.7 percent.	697	1,069
$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, interest from 1.3 to 3.1 percent. The Water utility's proportional share of the outstanding debt is 10.7 percent.	3,059	3,370
Total pension obligation bonds payable	3,756	4,439
REVENUE BONDS PAYABLE		
$58,235 2008 Water Revenue Series B Bonds: fixed rate bonds due in annual principal installments from $1,210 to $7,505 through October 1, 2038, interest from 4.0 to 5.0 percent	55,415	56,625
$31,895 2009 Water Refunding/Revenue Series A Bonds: fixed rate bonds due in annual principal installments from $2,270 to $2,625 through October 1, 2020, interest from 4.0 to 5.0 percent	7,255	9,760
$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 3.3 to 4.1 percent	67,790	67,790
$59,000 2011 Water Revenue/Refunding Series A Bonds: variable rate bonds due in annual principal installments from $1,475 to $3,950 through October 1, 2035. Interest rate is subject to weekly repricing (net interest rate, including swaps, at June 30, 2018 was 3.1 percent)	52,425	54,125
Total water revenue bonds payable	182,885	188,300
Total water revenue bonds, pension obligation bonds and contracts payable	187,578	193,676
Unamortized bond premium	1,749	2,064
Total water revenue bonds, pension obligation bonds and contracts payable, including bond premium	189,327	195,740
Less current portion	(6,513)	(6,248)
Total long-term water revenue bonds, pension obligation bonds and contracts payable	$ 182,814	$ 189,492

NOTE 4. LONG-TERM OBLIGATIONS (CONTINUED)

Revenue and pension obligation bonds annual debt service requirements, including contracts payable, to maturity, as of June 30, 2018, are as follows (in thousands):

	2019	2020	2021	2022	2023	2024-2028	2029-2033	2034-2038	2039-2043	TOTAL
Principal	$ 6,513	$ 6,620	$ 6,557	$ 6,803	$ 7,027	$ 38,238	$ 44,420	$ 54,120	$ 17,280	$ 187,578
Interest	7,556	7,299	7,048	6,808	6,566	28,307	20,007	10,002	595	94,188
Total	$ 14,069	$ 13,919	$ 13,605	$ 13,611	$ 13,593	$ 66,545	$ 64,427	$ 64,122	$ 17,875	$ 281,766

For fiscal year ended June 30, 2018, the City restructured the presentation of the long term pension obligation bonds from advances from other funds to long term obligations. The Water 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. The Water Utility's proportional share of the outstanding principal amount of the bonds was $3,756 and $4,439 as of June 30, 2018 and 2017, 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 CAFR for the fiscal year ended June 30, 2018.

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, 2018 and 2017, 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)	Annual Debt Service Payments	Debt Service Coverage Ratio
June 30, 2018	Water revenues	$ 30,287	$ 14,147	2.14
June 30, 2017	Water revenues	$ 27,733	$ 13,610	2.04

[1] Excludes GASB 68 Accounting and Financial Reporting for Pension non-cash adjustments of $3,119 and ($85) as expenses for June 30, 2018 and 2017 respectively.

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, 2018 is as follows:

	Notional Amount	Fair Value as of 6/30/2018	Change in Fair Value for Fiscal Year
2011 Water Refunding/Revenue Bonds Series A	$ 52,425	$ (5,593)	$ 2,600

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: Per the existing swap agreement, the Water Utility pays the counterparty a fixed payment and receives a variable payment computed as 62.68 percent of the London Interbank Offering Rate ("LIBOR") one-month index plus 12 basis points. The swap has a notional amount equal to the principal amount stated above. The notional value of the swap and principal amount of the associated debt decline by $1,475 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. As of June 30, 2018, rates were as follows:

Interest rate swap:	Terms	Rates
Fixed payment to counterparty	Fixed	3.20000%
Variable payment from counterparty	62.68 LIBOR + 12bps	(0.41887%)
Net interest rate swap payments		2.78113%
Variable-rate bond coupon payments		0.32721%
Synthetic interest on bonds		3.10834%

Fair value: As of June 30, 2018, in connection with the swap agreement, the transactions had a total negative fair value of ($5,593). 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.

Credit risk: As of June 30, 2018, the Water Utility was not exposed to credit risk because the swap had a negative fair value. The swap counterparty, J.P. Morgan Chase & Co. was rated A- 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, 2018, there is no requirement for collateral posting for the outstanding swap.

Basis risk: As noted above, the swap exposes the Water Utility to basis risk should the relationship between LIBOR 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, 2018, 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.

NOTE 4. LONG-TERM OBLIGATIONS (CONTINUED)

Fiscal Year Ending June 30,	Variable-Rate Bonds Principal	Interest	Interest Rate Swaps, Net	Total
2019	$ 1,475	$ 177	$ 1,507	$ 3,159
2020	2,375	170	1,444	3,989
2021	2,475	161	1,372	4,008
2022	2,525	153	1,298	3,976
2023	2,600	144	1,222	3,966
2024-2028	14,525	573	4,871	19,969
2029-2033	14,975	315	2,680	17,970
2034-2038	11,475	50	429	11,954
Total	$ 52,425	$ 1,743	$ 14,823	$ 68,991

NOTE PAYABLE

Note payable consists of several agreements with Hillwood Enterprises, L.P. and related entities (collectively Hillwood) for their development of logistic centers located in the City of San Bernardino. As a part of these agreements, the Water Utility leases land to Hillwood and also purchased land from Hillwood with a subsequent lease-back to the entity. In addition, the agreements require Hillwood to relocate wells located on the properties as well as terminate an existing lease. In consideration of the cost of the land purchase, well relocations and lease termination, the Water Utility will make payments to Hillwood in the form of a credit with Hillwood's rental payments to the Water Utility for the first 15 years of the leases. These agreements resulted in a total liability to the Water Utility of $21,524, as of June 30, 2018.

Estimated annual rent credits, which are adjusted annually based on Consumer Price Index (CPI), to be applied to the land purchase and well relocation agreements commencing in 2014 with an effective interest rate of 3.38 percent, are as follows (in thousands):

Fiscal Year	Principal	Interest	Total
2019	$ 683	$ 431	$ 1,114
2020	747	407	1,154
2021	815	380	1,195
2022	887	352	1,239
2023	963	320	1,283
2024-2028	6,104	1,038	7,142
2029-2033	2,854	94	2,948
Total	$ 13,053	$ 3,022	$ 16,075

Estimated annual rent credits, which are adjusted annually based on CPI, to be applied to the well relocation agreement commencing in 2017 with an effective interest rate of 3.15 percent, are as follows (in thousands):

NOTE 4. LONG-TERM OBLIGATIONS (CONTINUED)

Fiscal Year	Principal	Interest	Total
2019	$ 219	$ 125	$ 344
2020	226	117	343
2021	233	110	343
2022	241	103	344
2023	248	95	343
2024-2028	1,366	351	1,717
2029-2033	1,513	118	1,631
Total	$ 4,046	$ 1,019	$ 5,065

Annual rent credits to be applied for the lease termination agreement commencing in 2017, are as follows (in thousands):

Fiscal Year	Principal	Interest	Total
2019	$ 300	$ -	$ 300
2020	300	-	300
2021	300	-	300
2022	300	-	300
2023	300	-	300
2024-2028	1,500	-	1,500
2029-2033	1,425	-	1,425
Total	$ 4,425	$ -	$ 4,425

NOTE 5. EMPLOYEE RETIREMENT PLAN

PLAN DESCRIPTION

The City contributes to 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. 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.calpersca.gov. The Water Utility, including Water Conservation Programs, 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 percent 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 –
  - The retirement formula is 2.7 percent at age 55 for employees hired before October 19, 2011. Effective January 1, 2018 for unrepresented employees (Sr. Management, Management, Professional, Para-professional, Supervisory, Confidential, and Executive units), the employees were required to pay 2 percent of the employee contribution of their

pensionable income, with the City contributing the other 6 percent. Effective January 1, 2019, employees will be required to pay an additional portion of their pensionable income. This portion is a three year increase of 2 percent (2019), 2 percent (2020) and 2 percent (2021). By 2021, employees will be contributing the entire 8 percent of their pensionable income.

  - The retirement formula is 2.7 percent at age 55 for SEIU employees hired before June 7, 2011. The employee is required to pay 6 percent of their pensionable income with the City contributing the other 2 percent. Effective January 1, 2019, employees will be required to pay an additional portion of their pensionable income. This portion is a two year increase of 1 percent (2019) and 1 percent (2020). By 2020, employees will be contributing the entire 8 percent of their pensionable income

  - The retirement formula is 2.7 percent at age 55 for IBEW employees hired before October 19, 2011. Effective November 1, 2017 employees contributed 2 percent of their total pensionable income with the City paying the remaining 6 percent. Effective November 1, 2018, employees will be required to pay an additional portion of their pensionable income. This portion is a three year increase of 2 percent (2018), 2 percent (2019) and 2 percent (2020). By 2020, employees will be contributing the entire 8 percent of their pensionable income.

- 2nd Tier - The retirement formula is 2.7 percent at age 55, and:
  - SEIU employees hired on or after June 7, 2011 pay their share (8 percent) of contributions.
  - All other miscellaneous employees hired on or after October 19, 2011 pay their share (8 percent) of contributions.

- 3rd Tier – The retirement formula is 2 percent at age 62 for new members hired on or after January 1, 2013 and the employee must pay the employee share ranging from 7 percent to 8 percent based on bargaining group classification. 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.

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.

NOTE 5. EMPLOYEE RETIREMENT PLAN (CONTINUED)

EMPLOYEES COVERED

As of measurement date June 30, 2017 and 2016, the following employees, City-wide, were covered by the benefit terms of the Plan:

	Measurement Date	
	June 30, 2017	**June 30, 2016**
Inactive employees or beneficiaries currently receiving benefits	2,114	2,040
Inactive employees entitled to but not yet receiving benefits	1,325	1,317
Active employees	1,599	1,536

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 June 30, 2018, the net pension liability of the Plan is measured as of June 30, 2017, using an annual actuarial valuation as of June 30, 2016 rolled forward to June 30, 2017 using standard update procedures. For fiscal year June 30, 2017, the net pension liability of the Plan is measured as of June 30, 2016, using an annual actuarial valuation as of June 30, 2015 rolled forward to June 30, 2016 using standard update procedures. A summary of principal assumptions and methods used to determine the net pension liability is shown below.

NOTE 5. EMPLOYEE RETIREMENT PLAN (CONTINUED)

ACTUARIAL ASSUMPTIONS

The total pension liabilities in the June 30, 2016 and 2015 actuarial valuations were determined using the following actuarial assumptions:

	Miscellaneous - Current Year	Miscellaneous - Prior Year
Valuation Date	June 30, 2016	June 30, 2015
Measurement Date	June 30, 2017	June 30, 2016
Actuarial Cost Method	Entry-Age Normal Cost Method	Entry-Age Normal Cost Method
Actuarial Assumptions:		
Discount rate	7.15%	7.65%
Inflation	2.75%	2.75%
Payroll growth	3.00%	3.00%
Projected salary increase	(1)	(1)
Investment rate of return (2)	7.50%	7.50%
Mortality	(3)	(3)

(1) Depending on age, service and type of employment.

(2) Net of pension plan investment expenses, including inflation.

(3) The probabilities of mortaility are based on the 2014 CalPERS Experience Study for the period from 1997 to 2011. Pre-retirement mortality rates include 20 years of projected mortality improvement using Scale BB published by the Society of Actuaries.

DISCOUNT RATE

The discount rate used to measure the Plan's total pension liability was 7.15 percent and 7.65 percent for measurement date as of June 30, 2017 and 2016, respectively. To determine whether the municipal bond rate should be used in the calculation of a discount rate for the Plan, CalPERS stress tested plans that would most likely result in a discount rate that would be different from the actuarially assumed discount rate. Based on the testing, none of the tested plans run out of assets. Therefore, the discount rates used to measure total pension liability are adequate and the use of the municipal bond rate calculation is not necessary. The long term expected discount rates are applied to all plans in the Public Employees Retirement Fund. The stress test results are presented in a detailed report called "GASB Crossover Testing Report" that can be obtained from the CalPERS website.

The long-term expected rate of return on pension plan investments was determined using a building-block method in which best-estimate ranges of 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 as well as the expected pension fund cash flows. Using historical returns of all the funds' asset classes, expected compound returns were calculated over the short-term (first 10 years) and the long-term (11-60 years) using a building-block approach. Using the expected nominal returns for both short-term and long-term, the present value of benefits was calculated for each fund. The expected rate of return was set by calculating the single equivalent expected return that arrived at the same present value of benefits for cash flows as the one calculated using both short-term and long-term returns. The expected rate of return was then set equivalent to the single equivalent rate calculated above and rounded down to the nearest one quarter of one percent.

NOTE 5. EMPLOYEE RETIREMENT PLAN (CONTINUED)

The table below reflects long-term expected real rate of return by asset class. The rate of return was calculated using the capital market assumptions applied to determine the discount rate and asset allocation. These geometric rates of return are net of administrative expenses.

June 30, 2017 Measurement Date

Asset Class	Current Target Allocation	Real Return Years 1 - 10 (1)	Real Return Years 11 + (2)
Global Equity	47.00%	4.90%	5.38%
Global Fixed Income	19.00%	0.80%	2.27%
Inflation Sensitive	6.00%	0.60%	1.39%
Private Equity	12.00%	6.60%	6.63%
Real Estate	11.00%	2.80%	5.21%
Infrastructure and Forestland	3.00%	3.90%	5.36%
Liquidity	2.00%	-0.40%	-0.90%

(1) An expected inflation of 2.50% used for this period.
(2) An expected inflation of 3.00% used for this period.

June 30, 2016 Measurement Date

Asset Class	Current Target Allocation	Real Return Years 1 - 10 (1)	Real Return Years 11 + (2)
Global Equity	51.00%	5.25%	5.71%
Global Fixed Income	20.00%	0.99%	2.43%
Inflation Sensitive	6.00%	0.45%	3.36%
Private Equity	10.00%	6.83%	6.95%
Real Estate	10.00%	4.50%	5.13%
Infrastructure and Forestland	2.00%	4.50%	5.09%
Liquidity	1.00%	-0.55%	-1.05%

(1) An expected inflation of 2.50% used for this period.
(2) An expected inflation of 3.00% used for this period.

NOTE 5. EMPLOYEE RETIREMENT PLAN (CONTINUED)

CHANGES IN THE NET PENSION LIABILITY

The changes in the Water Utility's, including Water Conservation Programs, proportionate share of the net pension liability as of June 30, 2018 (measurement date June 30, 2017) and 2017 (measurement date June 30, 2016) for the Plan are as follows:

June 30, 2018		Net Pension Liabiltiy	Proportion of the Plan
Proportion - Reporting date June 30, 2018 (measurement date June 30, 2017)	$	38,880	11.44%
Proportion - Reporting date June 30, 2017 (measurement date June 30, 2016)		34,465	11.14%
Change - Increase / (Decrease)		4,415	0.30%
June 30, 2017			
Proportion - Reporting date June 30, 2017 (measurement date June 30, 2016)		34,465	11.14%
Proportion - Reporting date June 30, 2016 (measurement date June 30, 2015)		28,257	11.59%
Change - Increase / (Decrease)		6,208	(0.45%)

SENSITIVITY OF THE NET PENSION LIABILITY TO CHANGES IN THE DISCOUNT RATE

The following presents the Water Utility's, including Water Conservation Programs, proportionate share of the net pension liability of the Plan, calculated using the discount rate 7.15 percent and 7.65 percent for measurement date as of June 30, 2017 and 2016, respectively, 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:

		June 30, 2017			June 30, 2016	
	Discount Rate -1% (6.15%)	Current Discount Rate (7.15%)	Discount Rate +1% (8.15%)	Discount Rate -1% (6.65%)	Current Discount Rate (7.65%)	Discount Rate +1% (8.65%)
The Water Utility's proportionate share of the Plan's net pension liability	$ 60,851	$ 38,880	$ 20,883	$ 53,495	$ 34,465	$ 18,814

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

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

For the fiscal years ended June 30, 2018 and 2017, the Water Utility, including Water Conservation Programs, recognized pension expense of $6,319 and $3,200, respectively. At June 30, 2018 and 2017, the Water Utility, including Water Conservation Programs, reported deferred outflows of resources and deferred inflows of resources related to pension from the following sources:

	June 30, 2018		June 30, 2017	
	Deferred Outflows of Resources	Deferred Inflows of Resources	Deferred Outflows of Resources	Deferred Inflows of Resources
Pension contributions subsequent to measurement date	$ 3,227	$ -	$ 3,286	$ -
Difference between actual and actuarial determined contribution	-	-	1,075	-
Changes in assumptions	6,075	-	-	(1,212)
Differences between expected and actual experience	-	(2,585)	-	(1,418)
Net differences between projected and actual earnings on plan investments	1,579	-	9,181	(3,880)
Total	$ 10,881	$ (2,585)	$ 13,542	$ (6,510)

$3,227 reported as deferred outflows of resources related to contributions subsequent to the measurement date will be recognized as a reduction of the net pension liability in the year ended June 30, 2019.

Amounts reported as deferred outflows of resources and deferred inflows of resources related to pensions will be recognized as pension expense as follows:

Year Ended June 30	Deferred Outflows/ (Inflows) of Resources
2019	$ 1,076
2020	3,225
2021	1,559
2022	(791)
Total	$ 5,069

NOTE 6. OTHER POST-EMPLOYMENT BENEFITS (OPEB)

PLAN DESCRIPTION

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.

NOTE 6 - OTHER POST-EMPLOYMENT BENEFITS (OPEB) (CONTINUED)

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.

As of measurement date June 30, 2017, the following employees, City-wide, were covered by the benefit terms:

	Measurement Date June 30, 2017
Inactive plan members or beneficiaries currently receiving benefits	304
Inactive plan members entitled to but not yet receiving benefits	-
Active plan members	2,121
Total	2,425

ACTUARIAL ASSUMPTIONS

The total OPEB liability was determined by actuarial valuation as of June 30, 2017 using the following actuarial assumptions:

	Current Year
Valuation Date	June 30, 2017
Measurement Date	June 30, 2017
Funding Policy	Pay-as-you-go for implicit rate subsidy
Actuarial Assumptions:	
Discount rate [1]	3.40%
Inflation rate	2.75%
Salary inflation	3.00%
Salary increases [2]	--
Mortality	CalPERS 2014 Experience Study

[1] The discount rate is the average, rounded to 5 basis points, of the range of 3-20 year municipal bond rate indices: S&P Municipal Bond 20 Year High Grade Rate Index, Bond Buyer 20-Bond GO Index, and Fidelity GO AA 20 Year Bond Index.

[2] The benefits are not payroll related but the City's cost for each individual's projected City contribution is allocated over their lifetime as a level-percentage of pay. For cost method purposes the merit increases from the most recent CalPERS pension plan valuation will be used.

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

The following presents the Water Utility's, including Water Conservation Programs, proportionate share of the City's total OPEB liability, calculating using the healthcare trend rate of 6.00%/HMO and 6.50%/PPO, 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 (5.00%/HMO and 5.50%/PPO) or 1-percentage-point higher (7.00%/HMO and 7.50%/PPO) than the current rate:

	June 30, 2017 - Measurement Date		
	1% Decrease	Current healthcare cost trend rates	1% Increase
The Water Utility's proportionate share of the City's total OPEB liability	$ 3,065	$ 3,410	$ 3,813

SENSITIVITY OF TOTAL OPEB LIABILITY TO CHANGES IN DISCOUNT RATES

The following presents the Water Utility's, including Water Conservation Programs, proportionate share of the City's total OPEB liability, calculating using the discount rate of 3.40%, 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 (2.40%) or 1-percentage-point higher (4.40%) than the current rate:

	June 30, 2017 - Measurement Date		
	1% Decrease (2.40%)	Current Discount Rate (3.40%)	1% Increase (4.40%)
The Water Utility's proportionate share of the City's total OPEB liability	$ 3,697	$ 3,410	$ 3,148

CHANGE IN TOTAL OPEB LIABILITY

For fiscal year ended June 30, 2018, the Water Utility's, including Water Conservation Programs, recognized total OPEB expense of $265. The following table shows the change in the Water Utility's, including Water Conservation Programs, proportionate share of the City's total OPEB liability for the year ended June 30, 2018 (measurement date June 30, 2017):

June 30, 2018	Total OPEB Liability	Proportion to the City
Proportion - Reporting date June 30, 2018 (measurement date June 30, 2017)	$ 3,410	9.30%
Proportion - Beginning balance at July 1, 2017	3,391	9.30%
Change - Increase / (Decrease)	19	0.00%

NOTE 6 - OTHER POST-EMPLOYMENT BENEFITS (OPEB) (CONTINUED)

DEFERRED OUTFLOWS/INFLOWS OF RESOURCES RELATED TO OPEB

At June 30, 2018, the Water Utility, including Water Conservation Programs, reported deferred inflows of resources related to OPEB from the following sources:

	Deferred Inflows of Resources
Changes of assumptions	$ 112
Total	$ 112

Amounts reported as deferred inflows of resources related to OPEB will be recognized in OPEB expense as follows:

Year Ended June 30	Deferred Inflows of Resources
2019	$ (16)
2020	(16)
2021	(16)
2022	(16)
2023	(16)
Thereafter	(32)
Total	$ (112)

NOTE 7. 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 water 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 percent of the monthly accrued interest to be included in the reserve. Certain revenue/refunding bond issues are covered by a Surety Bond (2008B) and certain issues have no debt service reserve requirements (2009A & B and 2011A).

NOTE 8. CONSTRUCTION COMMITMENTS

As of June 30, 2018, the Water Utility had major commitments (encumbrances) of approximately $1,614 with respect to unfinished capital projects which is expected to be funded by unrestricted cash reserves.

NOTE 9. 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.

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, and no trial date has been set.

NOTE 10. PRIOR PERIOD ADJUSTMENTS

A prior period adjustment of ($125) was made to decrease the Water Utility's, including Water Conservation Programs, net position. The OPEB payable of $3,266 in 2017 was eliminated due to the implementation of GASB 75. The payable was the cumulative difference between annual OPEB costs and the Water's contribution. The adjustment was made to reflect the prior period costs related to other post-employment benefits. The restatement of beginning net position is as follows:

Net position at July 1, 2017, as previously stated	$	305,418
Other post-employment benefits adjustment		(125)
Net position at July 1, 2017, as restated	$	305,293

WATER UTILITY: KEY HISTORICAL OPERATING DATA

FISCAL YEAR	2017/18	2016/17	2015/16	2014/15	2013/14
WATER SUPPLY (ACRE FEET)					
Potable water production[1]	69,778	64,407	58,903	59,974	70,195
Percentage pumped[2]	100.00%	100.00%	100.00%	100.00%	100.00%
System peak day (gallons)[3]	83,000,000	81,000,000	75,000,000	74,000,000	90,000,000
WATER USE					
Number of meters as of year end					
Residential	59,601	59,453	59,137	58,922	58,958
Commercial/Industrial	5,705	5,640	5,619	5,594	5,527
Other	334	335	338	355	344
Total	65,640	65,428	65,094	64,871	64,829
CCF* sales					
Residential	15,564,143	14,219,498	13,125,476	15,424,999	17,432,384
Commercial/Industrial	9,573,518	8,683,382	8,011,884	9,511,177	10,292,548
Other	900,596	844,041	764,125	895,876	960,694
Subtotal	26,038,257	23,746,921	21,901,485	25,832,052	28,685,626
Wholesale	1,476,117	1,593,808	627,978	175,438	201,678
Total	27,514,374	25,340,729	22,529,463	26,007,490	28,887,304

*(CCF equals 100 cubic feet)

WATER FACTS					
Average annual CCF per residential customer	261	240	223	262	296
Average price ($/CCF) per residential customer	$2.39	$2.46	$2.44	$2.35	$2.33
Debt service coverage ratio (DSC)[4,5]	2.14	2.04	1.80	2.15	2.56
Employees[6]	159	174	181	181	182

[1] Water pumping figures have been adjusted to include retail and wholesale potable water production.

[2] No purchased water.

[3] System peak day has been adjusted to reflect production for retail customers.

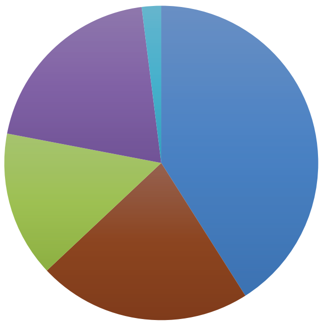
[4] Interest expense used to calculate DSC is net of federal subsidy on Build America Bonds.

[5] Does not include GASB 68 Accounting and Financial Reporting for Pension non-cash adjustments of $3,149, ($85), ($1,806), and ($941) for fiscal years 17/18 through FY 14/15, respectively.

[6] Approved positions.

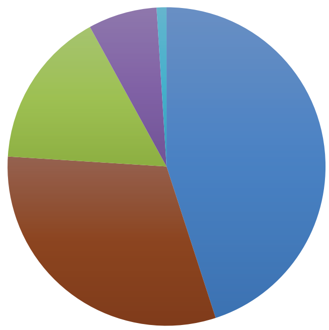
2017/2018 WATER REVENUE AND RESOURCES

SOURCE OF REVENUE



- Residential Sales 41¢
- Commercial Sales 22¢
- Other Revenue 15¢
- Use of Reserves 20¢
- Other Sales 2¢
- Investment Income (less than 1¢)

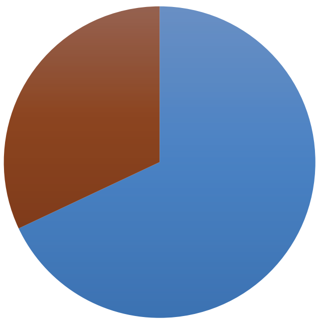
DISTRIBUTION OF REVENUE



- Operations and Maintenance 45¢
- Additions and Replacements to the System 31¢
- Debt Service 16¢
- Transfers to the City's General Fund* 7¢
- Water Conservation 1¢

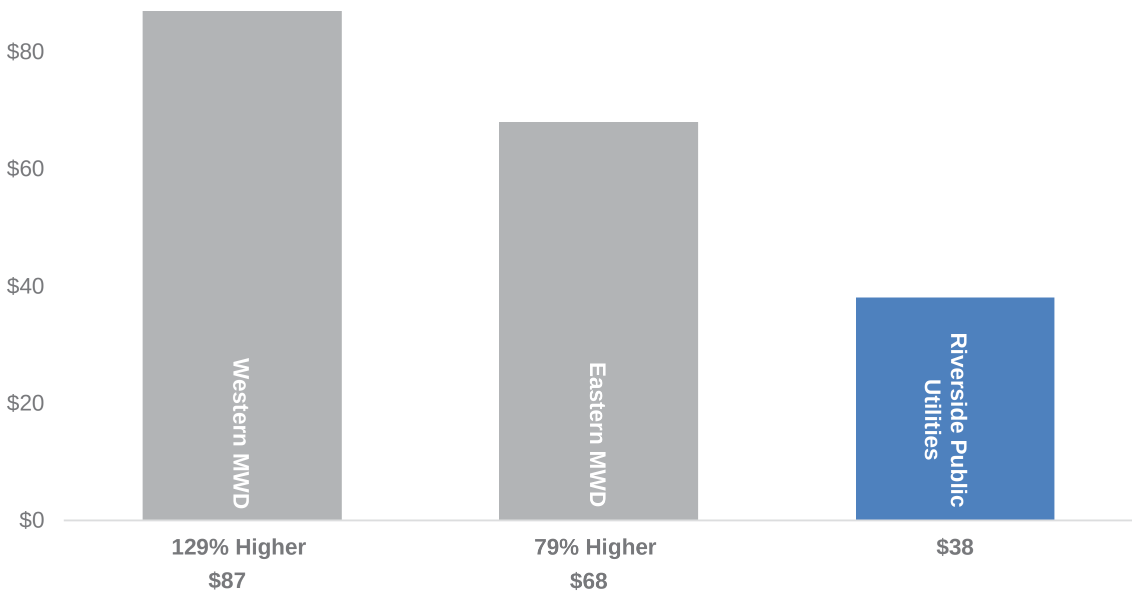
*Based on transfer of 11.5% of fiscal year 2016/2017 gross operating revenues including adjustments

WATER RESOURCES



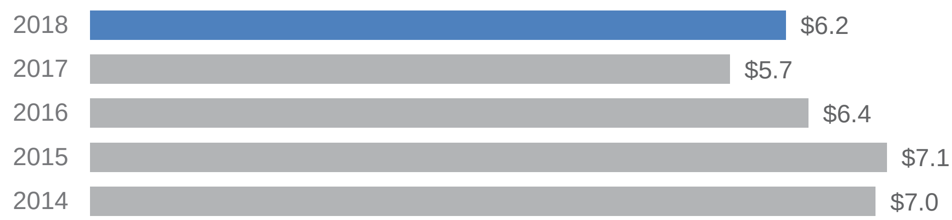
- San Bernardino Basin Wells 68%
- Riverside Basin Wells 32%
- Purchased Water 0%

RESIDENTIAL WATER RATE COMPARISON 19 CCF PER MONTH (AS OF JUNE 30, 2018)

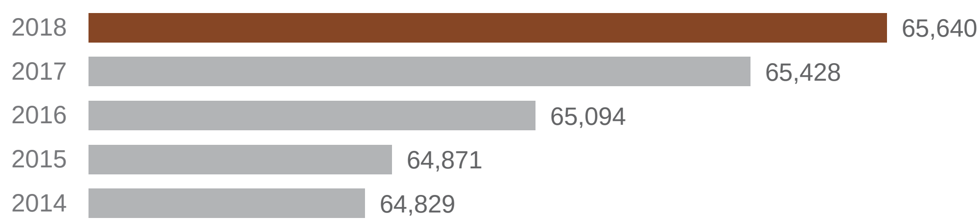


WATER KEY OPERATING INDICATORS

General Fund Transfer (In Millions)

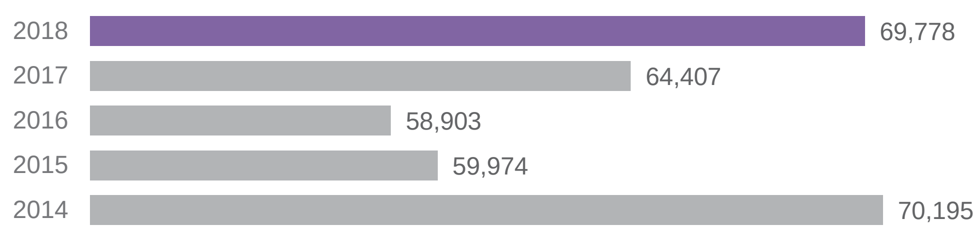


Number of Meters At Year End



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	325,801
Service Area Size (square miles)	74.20

System Data

Smallest Pipeline	2.0”
Largest Pipeline	72.0”
Miles of Pipeline	1,005
Number of Domestic Wells	56
Number of Active Reservoirs	16
Total Reservoir Capacity (gallons)	108,500,000
Number of Treatment Plants	6
Number of Treatment Vessels	84
Miles of Canal	14
Number of Fire Hydrants	8,173
Daily Average Production (gallons)	67,500,000
2017-2018 Peak Day (gallons)	83,000,000
07/9/17, 103 Degrees	
Historical Peak (gallons)	118,782,000
08/9/05, 99 Degrees	

Bond Ratings

Fitch Ratings	AA+
Moody’s	Aa2
Standard and Poor’s	AAA

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