Electric

FINANCIAL STATEMENTS

Riverside Energy Resource Center — used to generate energy during emergencies or when energy use has hit its peak on hot days.

STATEMENTS OF NET POSITION

ASSETS AND DEFERRED OUTFLOWS OF RESOURCES	June 30, 2014	June 30, 2013
	(in thousands)	
UTILITY PLANT:		
Utility plant, net of accumulated depreciation (Notes 3 and 10)	$ 691,416	$ 679,047
RESTRICTED ASSETS:		
Cash and investments at fiscal agent (Note 2)	176,349	211,072
OTHER NON-CURRENT ASSETS:		
Advances to other funds	5,800	5,742
Net pension asset	11,450	11,954
Unamortized purchased power (Note 8)	3,143	-
Regulatory assets	17,451	18,281
Total other non-current assets	37,844	35,977
Total non-current assets	905,609	926,096
CURRENT ASSETS:		
Unrestricted assets:		
Cash and cash equivalents (Note 2)	210,929	197,823
Accounts receivable, less allowance for doubtful accounts 2014 $647; 2013 $774	36,680	40,955
Advances to other funds	914	1,765
Accrued interest receivable	1,127	1,089
Inventory	1,202	507
Prepaid expenses	22,827	21,869
Unamortized purchased power (Note 8)	372	-
Total unrestricted current assets	274,051	264,008
Restricted assets:		
Cash and cash equivalents (Note 2)	18,958	16,735
Public Benefit Programs - cash and cash equivalents (Note 2)	8,920	8,856
Public Benefit Programs receivable	939	922
Total restricted current assets	28,817	26,513
Total current assets	302,868	290,521
Total assets	1,208,477	1,216,617
DEFERRED OUTFLOWS OF RESOURCES:		
Deferred changes in derivative values	16,336	17,371
Deferred loss on refunding	12,952	11,917
Total deferred outflows of resources	29,288	29,288
Total assets and deferred outflows of resources	$ 1,237,765	$ 1,245,905

See accompanying notes to the financial statements

STATEMENTS OF NET POSITION

NET POSITION AND LIABILITIES	June 30, 2014	June 30, 2013
	(in thousands)	
NET POSITION:		
Net investment in capital assets	$ 196,771	$ 201,765
Restricted for:		
Regulatory requirements (Note 5)	3,150	381
Debt service (Note 5)	15,808	16,354
Public Benefit Programs	9,732	9,076
Unrestricted	258,514	241,696
Total net position	483,975	469,272
LONG-TERM OBLIGATIONS, LESS CURRENT PORTION (NOTE 4)	593,108	563,203
OTHER NON-CURRENT LIABILITIES:		
Compensated absences (Note 4)	830	762
Advances from other funds - pension obligation (Note 4)	11,284	11,781
Nuclear decommissioning liability (Note 4)	75,299	76,167
Postemployment benefits payable (Note 4)	5,749	4,928
Derivative instruments (Note 4)	22,108	23,729
Loan payable (Note 4)	-	7,413
Capital leases payable (Note 4)	1,566	1,913
Total non-current liabilities	116,836	126,693
CURRENT LIABILITIES PAYABLE FROM RESTRICTED ASSETS:		
Accounts payable and other accruals	1,869	718
Accrued interest payable	5,770	5,970
Public Benefit Programs payable	154	643
Current portion of long-term obligations (Note 4)	14,920	20,685
Total current liabilities payable from restricted assets	22,713	28,016
CURRENT LIABILITIES:		
Accounts payable and other accruals	17,289	20,102
Customer deposits	3,844	3,371
Loan payable (Note 4)	-	35,248
Total current liabilities	21,133	58,721
Total liabilities	753,790	776,633
Total net position and liabilities	$ 1,237,765	$ 1,245,905

See accompanying notes to the financial statements

STATEMENTS OF REVENUES, EXPENSES AND CHANGES IN NET POSITION

	For the Fiscal Years Ended June 30, 2014	2013
	(in thousands)	
OPERATING REVENUES:		
Residential sales	$ 111,880	$ 118,173
Commercial sales	67,063	66,632
Industrial sales	111,260	110,680
Other sales	5,600	5,712
Wholesale sales	115	638
Transmission revenue	32,630	32,688
Other operating revenue	6,912	4,486
Public Benefit Programs	8,577	8,924
Total operating revenues before uncollectibles	344,037	347,933
Estimated uncollectibles, net of bad debt recovery	(589)	(959)
Total operating revenues, net of uncollectibles	343,448	346,974
OPERATING EXPENSES:		
Production and purchased power	138,822	131,461
Transmission	51,939	45,957
Distribution	50,374	49,579
Public Benefit Programs	7,933	7,868
Depreciation	27,260	28,728
Total operating expenses	276,328	263,593
Operating income	67,120	83,381
NON-OPERATING REVENUES (EXPENSES):		
Investment income	6,041	3,060
Interest expense and fiscal charges	(27,499)	(27,623)
Gain on sale of assets	293	584
Other	3,444	3,520
Total non-operating revenues (expenses)	(17,721)	(20,459)
Income before capital contributions and transfers out	49,399	62,922
Capital contributions	4,008	4,980
Transfers out - contributions to the City's general fund	(38,704)	(37,186)
Total capital contributions and transfers out	(34,696)	(32,206)
Income before extraordinary item	14,703	30,716
EXTRAORDINARY ITEM:		
Power plant closure	-	(41,259)
Increase (decrease) in net position	14,703	(10,543)
NET POSITION, BEGINNING OF YEAR	469,272	479,815
NET POSITION, END OF YEAR	$ 483,975	$ 469,272

See accompanying notes to the financial statements

STATEMENTS OF CASH FLOWS

		For the Fiscal Years Ended June 30, 2014	2013
		(in thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:			
Cash received from customers and users		$ 348,296	$ 341,417
Cash paid to suppliers and employees		(255,926)	(242,735)
Other receipts		3,444	3,520
Payments related to extraordinary item		-	(3,707)
Net cash provided by operating activities		95,814	98,495
CASH FLOWS FROM NON-CAPITAL FINANCING ACTIVITIES:			
Transfers out - contributions to the City's general fund		(38,704)	(37,186)
Payment on advances to other funds - pension obligation		(497)	(437)
Cash received on advances to other funds		793	512
Net cash used by non-capital financing activities		(38,408)	(37,111)
CASH FLOWS FROM CAPITAL AND RELATED FINANCING ACTIVITIES:			
Purchase of utility plant		(36,349)	(35,498)
Proceeds from the sale of utility plant		457	646
Proceeds from revenue bonds, for payment of interest		2,315	-
Principal paid on long-term obligations		(21,827)	(19,942)
Interest paid on long-term obligations		(29,400)	(28,772)
Capital contributions		2,774	4,193
Bond issuance costs		(454)	(40)
Net cash used by capital and related financing activities		(82,484)	(79,413)
CASH FLOWS FROM INVESTING ACTIVITIES:			
Proceeds from (purchase of) investment securities		5,301	(1,549)
Income from investments		5,748	2,691
Net cash provided by investing activities		11,049	1,142
Net decrease in cash and cash equivalents		(14,029)	(16,887)
CASH AND CASH EQUIVALENTS, BEGINNING OF YEAR **(including $137,262 and $164,431 at June 30, 2013 and June 30, 2012, respectively, reported in restricted accounts)**		335,085	351,972
CASH AND CASH EQUIVALENTS, END OF YEAR **(including $110,127 and $137,262 at June 30, 2014 and June 30, 2013, respectively, reported in restricted accounts)**		$ 321,056	$ 335,085
RECONCILIATION OF OPERATING INCOME TO NET CASH PROVIDED BY OPERATING ACTIVITIES:			
Operating income		$ 67,120	$ 83,381
Adjustments to reconcile operating income to net cash provided by operating activities:			
Depreciation		27,260	28,728
Amortization of net pension asset		504	426
Other regulatory assets		-	(1,487)
Decrease in allowance for uncollectible accounts		(127)	(380)
Decrease (increase) in accounts receivable		4,501	(5,400)
Increase in inventory		(695)	(507)
Increase in prepaid expenses		(958)	(1,851)
Unamortized purchased power		(3,515)	-
Increase in regulatory assets		-	(11,779)
(Decrease) increase in accounts payable and other accruals		(1,725)	2,184
Increase (decrease) in compensated absences		68	(41)
Increase in postemployment benefits payable		821	1,119
Decrease in Public Benefit Programs		(489)	(392)
Increase in customer deposits		473	223
(Decrease) increase in decommissioning liability		(868)	4,458
Other receipts		3,444	3,520
Payments related to extraordinary item		-	(3,707)
Net cash provided by operating activities		$ 95,814	$ 98,495
SCHEDULE OF NON-CASH INVESTING, CAPITAL AND FINANCING ACTIVITIES:			
Capital contributions - capital assets		1,118	1,423
Borrowing under capital lease		408	1,659
Decrease in fair value of investments		(80)	(2,947)
Loss on power plant closure		-	(37,552)
Proceeds of refunding debt placed into an irrevocable trust:			
Defeasance of bonds		37,575	-
Payment of loan payable		42,661	-

See accompanying notes to the financial statements

Electric

NOTES TO THE FINANCIAL STATEMENTS

Installing turbine generator at Riverside Energy Resource Center.

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The Electric Utility (the Utility) exists under, and by virtue of, the City of Riverside (the City) Charter enacted in 1883. The 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 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 Utility on a separate fund basis. All amounts, unless otherwise indicated, are expressed in thousands of dollars.

BASIS OF ACCOUNTING

The 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. Effective July 1, 2012, the Utility adopted Governmental Accounting Standards Board (GASB) Statement No. 62, *Codification of Accounting and Financial Reporting Guidance Contained in Pre-November 30, 1989 FASB and AICPA Pronouncements* (GASB 62), which incorporates into the GASB's authoritative literature certain accounting and financial reporting guidance from all sources of generally accepted accounting principles for state and local governments issued on or before November 30, 1989 so that they derive from a single source. The accounting records of the Utility are also substantially in conformity with the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission (FERC). The Utility is not subject to the regulations of the FERC.

The 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 Utility are charges to customers for electric sales and services. Operating expenses for the 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.

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 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 $15,128 at June 30, 2014, and $15,324 at June 30, 2013.

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

UTILITY PLANT AND DEPRECIATION

The 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 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.

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

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	3-5 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.

In January 1998, the 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 Utility policy, the 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. The 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 Utility values its cash and investments in accordance with the provisions of the GASB Statement No. 31, *Accounting and Financial Reporting for Certain Investments and External Investment Pools* (GASB 31), which requires governmental entities, including governmental external investment pools, to report certain investments at fair value in the Statements of Net Position and recognize the corresponding change in the fair value of investments in the year in which the change occurred. Fair value is determined using quoted market prices.

Cash accounts of all funds are pooled for investment purposes to enhance safety and liquidity, while maximizing interest earnings.

City-wide information concerning cash and investments as of June 30, 2014, including authorized investments, custodial credit risk, credit and interest rate risk for debt securities and concentration of investments, carrying amount and market value of deposits and investments may be found in the notes to the City's "Comprehensive Annual Financial Report."

CASH AND INVESTMENTS AT FISCAL AGENTS

Cash and investments maintained by fiscal agents are considered restricted by the 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 Utility's proportionate share of Units 2 and 3 at San Onofre Generating Station (SONGS).

INTERNALLY RESTRICTED CASH RESERVES

The Utility has several cash reserves established for strategic purposes, all of which are considered internally restricted assets. The balances as of June 30, 2014 and 2013 respectively are as follows: Regulatory Risk Reserve $15,000 and $15,000, Energy Risk Management Reserve $30,000 and $30,000, Operating Reserve $131,031 and $116,031, and Decommissioning Reserve $1,725 and $132, for a combined total of $177,756 and $161,163 and are included as a component of unrestricted cash and cash equivalents in the accompanying Statements of Net Position.

ADVANCES TO OTHER FUNDS

Advances to other funds have been recorded as a result of agreements between the Utility and the City. The balances as of June 30, 2014 and 2013 are $6,714 and $7,507, respectively.

DERIVATIVES

The Utility accounts for derivative instruments using GASB Statement No. 53, *Accounting and Financial Reporting for Derivative Instruments* (GASB 53). This Statement requires the 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 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 Utility's interest rate swaps.

Various transactions permitted in the 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 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 Utility to provide for the future decommissioning of its ownership share of the nuclear units at San Onofre. The 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 cost estimate as of July 2013, prepared by ABZ Incorporated, the Utility has fully funded the SONGS nuclear decommissioning liability. With the recent retirement of SONGS units 2 and 3, 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 Utility has conservatively decided to continue to set aside $1,581 per year in an internally restricted cash reserve for unexpected costs not contemplated in the current estimates.

Increases to the funds held for decommissioning liability are from amounts set aside and investment earnings. The investment earnings are included in investment income in the Utility's financial statements. These earnings, as well as amounts set aside, are reflected as decommissioning expense which is considered part of production and purchased power. The Utility has set aside $77,897 and $76,035 in cash investments with the trustee and $1,725 and $132 in an internally restricted decommissioning reserve as the Utility's estimated share of the decommissioning cost of San Onofre as of June 30, 2014 and 2013, respectively, and these amounts are reflected as restricted assets and unrestricted cash and cash equivalents, respectively, on the Statements

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

of Net Position. The Utility's decommissioning liability is equivalent to the total funds accumulated less $4,323 and $0, paid as decommissioning costs for the fiscal years ended June 30, 2014 and 2013, respectively, and is reflected as an other non-current liability. The plant site easement at San Onofre terminates May 2024. The plant must be decommissioned and the site restored by the time the easement terminates. See Note 7 for further discussion of SONGS decommissioning.

CAPITAL LEASES

The Utility has entered into fourteen capital lease agreements as a lessee for financing fourteen compressed natural gas heavy duty service trucks. In fiscal year ended June 30, 2014, the Utility entered into one additional capital lease agreement for financing an additional service truck. All leases have seven year terms of monthly payments with interest rates ranging from 2.50% to 5.87%. The total gross value of all leases is $4,811 with depreciation over the seven year terms of the leases using the straight-line method.

As of June 30, 2014 and 2013, the total liability was $2,266 and $2,550, respectively, with the current portion included in accounts payable and other accruals. The remaining annual lease payments for the life of the leases are $751 in fiscal year ended June 30, 2015, $387 in fiscal year ended June 30, 2016, $322 annually through fiscal year ended June 30, 2019, and $309 in the fiscal year ended June 30, 2020. Total outstanding lease payments are $2,413, with $2,266 representing the present value of the net minimum lease payments and $147 representing interest.

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 Utility's portion of these deposits as of June 30, 2014 and 2013 was $3,844 and $3,371, respectively.

COMPENSATED ABSENCES

The accompanying financial statements include accruals for salaries, fringe benefits and compensated absences due to employees at June 30, 2014 and 2013. The 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 $4,442 at June 30, 2014 and $4,359 at June 30, 2013.

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 Utility participates in a self-insurance program for workers' compensation and general liability coverage that is administered by the City. The 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 risk for the year ended June 30, 2014, may be found in the notes to the City's "Comprehensive Annual Financial Report."

Although the ultimate amount of losses incurred through June 30, 2014 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 Utility including the Public Benefit Programs, were $786 and $818 for the years ended June 30, 2014 and 2013, respectively. Any losses above the City's reserves would be covered through increased rates charged to the Utility in future years.


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Customer-owned since 1895
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is an arbiter of airtime,
a broadcaster for business,
and a master of the mic.
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NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

EMPLOYEE RETIREMENT PLAN

The City contributes to the California Public Employees Retirement System (PERS), an agent multiple employer public employee defined benefit pension plan. PERS provides retirement and disability benefits, annual cost-of-living adjustments, and death benefits to plan members and beneficiaries. PERS 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.

All permanent full-time and selected part-time employees are eligible for participation in PERS. Benefits vest after five years of service and are determined by a formula that considers the employee's age, years of service and salary. The City has the following multiple tier retirement plan with benefits varying by plan for non-safety employees:

> 1st Tier – The retirement formula is 2.7% at age 55. The Utility pays the employee share (8%) of contributions on their behalf and for their account except for general Service Employees International Union (SEIU) employees, which contributed 2% in fiscal year 2014, with the City paying the remaining 6% of the employee share.
>
> 2nd Tier – The retirement formula is 2.7% at age 55. Employees hired on or after October 19, 2011 pay their share (8%) of contributions.
>
> 3rd Tier – The retirement formula is 2% at age 62 for new members hired on or after January 1, 2013. Employees must pay the employee share ranging from 7-8% based on bargaining group classification. Classic members (PERS members prior to 12/31/12) hired on or after January 1, 2013 may be placed in a different tier.

The Utility is required to contribute the remaining amounts necessary to fund the benefits for its employees using the actuarial basis recommended by the PERS actuaries and actuarial consultants and adopted by the PERS Board of Administration. The Utility's total contribution to PERS for the years ended June 30, 2014 and 2013 was $8,542 and $8,633 respectively. The employer portion of the PERS funding for the years ended June 30, 2014 and 2013 was 18.31 percent and 18.28 percent, respectively, of annual covered payroll.

City-wide information concerning elements of the unfunded actuarial accrued liabilities, contributions to PERS for the year ended June 30, 2014 and recent trend information may be found in the notes to the City's "Comprehensive Annual Financial Report."

PENSION OBLIGATION BONDS AND NET PENSION ASSET

The Utility is obligated to pay its share of the City's pension obligation bonds, which the City issued in 2005. The Utility's proportional share of the outstanding principal amount of the bonds was $11,284 and $11,781 as of June 30, 2014 and 2013, respectively, and is shown on the Statements of Net Position as Advances from other funds – pension obligation. The bond proceeds were deposited with PERS to fund the unfunded actuarial accrued liability for non-safety employees. The net pension asset will be amortized over 19 years in accordance with the method used by PERS for calculating actuarial gains and losses. The balance in the net pension asset as of June 30, 2014 and 2013 was $11,450 and $11,954, respectively. For more discussion relating to the City's issue, see the notes to the City's "Comprehensive Annual Financial Report" for the fiscal year ended June 30, 2014.

OTHER POSTEMPLOYMENT BENEFITS

The City provides healthcare benefits to retirees in the form of an implied rate subsidy. Retirees and active employees are insured together as a group, thus creating a lower rate for retirees than if they were insured separately. Although the retirees are solely responsible for the cost of their health insurance benefits through this plan, the retirees receive the benefit of a lower rate. The difference between these amounts is the implied rate subsidy, which is considered an other postemployment benefit (OPEB) under GASB Statement No. 45, *Accounting and Financial Reporting by Employers for Postemployment Benefits Other Than Pensions* (GASB 45).

Retiree coverage terminates either when the retiree becomes covered under another employer health plan, or when the retiree reaches Medicare eligibility age, which is currently age 65. Spousal coverage is available until the retiree becomes covered under another employer health plan, attains Medicare eligibility age, or dies. However, the retiree benefit continues to the surviving spouse if the retiree elects the PERS survivor annuity.

The contribution requirements are established by the City Council. The City is not required by law or contractual agreement to provide funding other than the pay-as-you-go amount necessary to provide current benefits to eligible retirees and beneficiaries.

The Utility's annual OPEB cost (expense) is reported based on the annual required contribution (ARC) of the employer, an amount actuarially determined in accordance with GASB 45. The ARC represents a level of funding that, if paid on an ongoing basis, is projected to cover normal cost each year and amortize any unfunded actuarial liability (or funding excess) (UAAL) over a period not to exceed thirty years. The Utility's OPEB liability as of June 30, 2014 and 2013 was $5,749 and $4,928, respectively.

City-wide information concerning the description of the plan, funding policy and annual OPEB cost, funding status and funding progress, and actuarial methods and assumptions for the year ended June 30, 2014 can be found in the notes to the City's "Comprehensive Annual Financial Report."

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.

When applicable, the Statements of Net Position will report a separate section for deferred inflows of resources. 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.

REGULATORY ASSETS

In accordance with GASB 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 City is recovering or expects to recover or refund such amounts in rates charged to its customers. Accordingly, regulatory assets relating to debt issuance costs and replacement power costs have been recorded by the Utility.

NET POSITION

The 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) and unamortized debt expenses 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."

CONTRIBUTIONS TO THE CITY'S GENERAL FUND

Pursuant to the City of Riverside Charter, the 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, 2014 and 2013, $38,704 and $37,186, respectively was transferred representing 11.5 percent.

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

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 Utility presents, and the City Council adopts, an annual budget. The proposed budget includes estimated expenses and forecasted revenues. The City Council adopts the Utility's budget in June each year via resolution.

RECLASSIFICATIONS

Certain reclassifications have been made to prior year's financial statements to conform to the current year's presentation.

NOTE 2. CASH AND INVESTMENTS

Cash and investments at June 30, 2014 and 2013, consist of the following (in thousands):

	June 30, 2014	June 30, 2013
	Fair Value	
Equity interest in City Treasurer's investment pool	$ 238,807	$ 223,414
Cash and investments at fiscal agent	176,349	211,072
Total cash and investments	$ 415,156	$ 434,486

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

	June 30, 2014	June 30, 2013
Unrestricted cash and cash equivalents	$ 210,929	$ 197,823
Restricted cash and cash equivalents	27,878	25,591
Restricted cash and investments at fiscal agent	176,349	211,072
Total cash and investments	$ 415,156	$ 434,486

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

Cash and investments distribution by maturities as of June 30, 2014 and 2013, are as follows:

Investment Type	June 30, 2014 Fair Value	Remaining Maturity (In Months) 12 Months or less	13 to 24 Months	25 to 60 Months	More than 60 Months
Held by fiscal agent					
Money market funds	$ 5,462	$ 5,462	$ -	$ -	$ -
Federal agency securities	53,165	-	9,113	44,052	-
Investment contracts [1]	97,040	4,030	-	82,249	10,761
Corp medium term notes	20,682	-	2,057	18,625	-
City Treasurer's investment pool [2]					
Money market funds	4,512	4,512	-	-	-
Federal agency securities	48,608	-	32,590	16,018	-
US Treasury notes/bonds	84,377	-	14,211	70,166	-
Corp medium term notes	33,275	7,511	12,488	13,276	-
State investment pool	60,633	60,633	-	-	-
Negotiable certificate of deposit	7,402	2,419	3,315	1,668	-
Total	$ 415,156	$ 84,567	$ 73,774	$ 246,054	$ 10,761

Investment Type	June 30, 2013 Fair Value	Remaining Maturity (In Months) 12 Months or less	13 to 24 Months	25 to 60 Months	More than 60 Months
Held by fiscal agent					
Money market funds	$ 3,142	$ 3,142	$ -	$ -	$ -
Federal agency securities	53,344	-	-	53,344	-
Investment contracts [1]	134,003	119,211	4,031	-	10,761
Corp medium term notes	20,583	-	-	20,583	-
City Treasurer's investment pool [2]					
Money market funds	31,975	31,975	-	-	-
Federal agency securities	101,606	17,490	9,648	74,468	-
Corp medium term notes	31,718	5,448	9,442	16,828	-
State investment pool	52,048	52,048	-	-	-
Negotiable certificate of deposit	6,067	2,701	1,953	1,413	-
Total	$ 434,486	$ 232,015	$ 25,074	$ 166,636	$ 10,761

Presented below is the actual rating as of June 30, 2014 and 2013 for each investment type:

Investment Type	June 30, 2014 Fair Value	Rating as of Year End AAA	AA+	AA	A+	A	Unrated
Held by fiscal agent							
Money market funds	$ 5,462	$ 5,420	$ -	$ -	$ -	$ -	$ 42
Federal agency securities	53,165	53,165	-	-	-	-	-
Investment contracts [1]	97,040	-	-	-	-	-	97,040
Corp medium term notes	20,682	-	2,057	8,281	6,017	4,327	-
City Treasurer's investment pool [2]							
Money market funds	4,512	648	-	787	-	3,077	-
Federal agency securities	48,608	48,608	-	-	-	-	-
US Treasury notes/bonds	84,377	84,377	-	-	-	-	-
Corp medium term notes	33,275	-	-	27,014	-	6,261	-
State investment pool	60,633	-	-	-	-	-	60,633
Neg certificate of deposit	7,402	-	-	-	-	-	7,402
Total	$ 415,156	$ 192,218	$ 2,057	$ 36,082	$ 6,017	$ 13,665	$ 165,117

NOTE 2. CASH AND INVESTMENTS (CONTINUED)

Investment Type	June 30, 2013 Fair Value	Rating as of Year End AAA	AA+	AA	A+	A	Unrated
Held by fiscal agent							
Money market funds	$ 3,142	$ 3,104	$ -	$ -	$ -	$ -	$ 38
Federal agency securities	53,344	53,344	-	-	-	-	-
Investment contracts [1]	134,003	-	-	-	-	-	134,003
Corp medium term notes	20,583	-	2,080	8,364	5,871	4,268	-
City Treasurer's investment pool [2]							
Money market funds	31,975	1,357	-	673	-	29,945	-
Federal agency securities	101,606	101,606	-	-	-	-	-
Corp medium term notes	31,718	-	-	26,184	-	5,534	-
State investment pool	52,048	-	-	-	-	-	52,048
Neg certificate of deposit	6,067	-	-	-	-	-	6,067
Total	$ 434,486	$ 159,411	$ 2,080	$ 35,221	$ 5,871	$ 39,747	$ 192,156

[1] Amounts related to bond construction proceeds are invested in specific maturities but are available for construction of capital assets as funding is needed.

[2] Additional information on investment types and credit risk may be found in the City's "Comprehensive Annual Financial Report."

NOTE 3. UTILITY PLANT

The following is a summary of changes in utility plant during the fiscal years ended June 30, 2014 and 2013 (in thousands):

	Balance As of 6/30/2012	Additions	Retirements/ Transfers	Balance As of 6/30/2013	Additions	Retirements/ Transfers	Balance As of 6/30/2014
Production [1, 2]	$ 349,264	$ -	$ (82,473)	$ 266,791	$ 361	$ -	$ 267,152
Transmission	32,054	3,122	-	35,176	7,787	-	42,963
Distribution	494,918	20,496	(1,078)	514,336	30,469	(3,424)	541,381
General	53,793	5,188	(154)	58,827	2,363	(590)	60,600
Intangibles	292	-	-	292	33	-	325
Depreciable utility plant	930,321	28,806	(83,705)	875,422	41,013	(4,014)	912,421
Less accumulated depreciation:							
Production [1, 2]	(102,951)	(10,191)	69,108	(44,034)	(8,907)	-	(52,941)
Transmission	(13,492)	(734)	-	(14,226)	(818)	-	(15,044)
Distribution	(172,283)	(13,480)	1,061	(184,702)	(14,073)	3,424	(195,351)
General	(22,308)	(2,987)	109	(25,186)	(3,400)	569	(28,017)
Intangibles	(5)	(58)	-	(63)	(62)	-	(125)
Accumulated depreciation	(311,039)	(27,450)	70,278	(268,211)	(27,260)	3,993	(291,478)
Net depreciable utility plant	619,282	1,356	(13,427)	607,211	13,753	(21)	620,943
Nuclear fuel, at amortized cost [2]	8,832	1,317	(10,149)	-	-	-	-
Production [1, 2]	14,641	-	(14,641)	-	-	-	-
Land	7,654	29	-	7,683	1,034	-	8,717
Intangibles, non-amortizable	9,821	830	-	10,651	-	-	10,651
Construction in progress	43,205	37,970	(27,673)	53,502	37,778	(40,175)	51,105
Nondepreciable utility plant	75,321	38,829	(42,314)	71,836	38,812	(40,175)	70,473
Total utility plant	$ 703,435	$ 41,502	$ (65,890)	$ 679,047	$ 52,565	$ (40,196)	$ 691,416

[1] SONGS Units 2 and 3 were taken offline in January 2012 and remained offline for extensive inspections, testing and analysis resulting from excessive wear of tubes in the steam generators. It was anticipated that Unit 2 would restart months in advance of Unit 3. Due to the uncertainty of Unit 3 restart date, the capital assets of Unit 3 were reclassified from a depreciable to a non-depreciable utility plant asset for fiscal year ended June 30, 2012.

[2] On June 7, 2013, Southern California Edison (SCE) announced its decision to permanently shut down both SONGS Units 2 and 3. As a result, both Units 2 and 3 and related nuclear fuel were written off from utility plant assets as an extraordinary item (Note 7 and 10).

NOTE 4. LONG-TERM OBLIGATIONS

The following is a summary of changes in long-term obligations during the fiscal years ended June 30, 2014 and 2013 (in thousands):

	Balance As of 6/30/2012	Additions	Reductions	Balance As of 6/30/2013	Additions	Reductions	Balance As of 6/30/2014	Due Within One Year
Revenue bonds	$ 603,123	$ -	$ (19,504)	$ 583,619	$ 84,841	$ (60,446)	$ 608,014	$ 14,920
Arbitrage liability	190	79	-	269	-	(255)	14	-
Advances from other funds - pension obligation	12,003	214	(436)	11,781	-	(497)	11,284	-
Postemployment benefits payable	3,809	1,119	-	4,928	821	-	5,749	-
Nuclear decommissioning liability	71,709	4,458	-	76,167	3,455	(4,323)	75,299	-
Capital leases	1,303	1,659	(412)	2,550	408	(692)	2,266	700
Loan payable	44,141	-	(1,480)	42,661	-	(42,661)	-	-
Compensated absences	4,294	3,609	(3,544)	4,359	3,629	(3,545)	4,443	3,613
Total long-term obligations	$ 740,572	$ 11,138	$ (25,376)	$ 726,334	$ 93,154	$ (112,419)	$ 707,069	$ 19,233

LOAN PAYABLE

The Utility entered into the Clearwater Power Plant Purchase and Sale Agreement dated March 3, 2010 with the City of Corona for the acquisition of Clearwater Cogeneration Facility (Clearwater) located in Corona. Clearwater is a combined-cycle, natural gas generating facility with a gross plant output of 29.5 megawatts (MW). Following a “transition period” during which the Utility engaged in pre-closing activities and due diligence inspection, the transaction closed on September 1, 2010 and the Utility took ownership of the plant. The purchase also included construction of a substation and the 69,000 volt facilities necessary to transfer power from Clearwater Power Plant to the Southern California Edison's (SCE) electrical distribution system to California’s high voltage transmission grid. The useful life of Clearwater and the related transmission facilities is anticipated to be at least thirty years. The total purchase price for Clearwater was $45,569, and the related outstanding obligation of $42,661 was prepaid with a portion of the proceeds of the 2013 Electric Revenue Refunding Bonds issued on July 25, 2013.

NOTE 4. LONG-TERM OBLIGATIONS (CONTINUED)

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

REVENUE BONDS PAYABLE

	June 30, 2014	June 30, 2013
$75,405 2003 Electric Refunding/Revenue Bonds: serial bonds due in a final principal installment of $6,880 on October 1, 2013, interest of 4.6 percent	$ -	$ 6,880
$27,500 2004 Electric Revenue Series A Bonds: serial bonds due in a final principal installment of $2,645 on October 1, 2014, interest of 5.0 percent	2,645	6,340
$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, 2014 was 3.0 percent). Partially refunded $13,975 on July 25, 2013 with the 2013 Electric Revenue Refunding Bonds	70,540	84,515
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, 2014 was 3.1 percent). Partially refunded $11,775 on July 25, 2013 with the 2013 Electric Revenue Refunding Bonds	41,975	53,750
$209,740 2008 Electric Revenue Series D Bonds: fixed rate bonds due in annual principal installments from $3,460 to $25,345, from October 1, 2017 through October 1, 2038, interest from 3.6 to 5.0 percent	209,740	209,740
$34,920 2009 Electric Refunding/Revenue Series A Bonds: fixed rate bonds due in annual principal installments from $1,150 to $7,035 through October 1, 2018, interest from 4.0 to 5.0 percent	13,815	21,075
$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 $95 to $2,440, from October 1, 2016 through October 1, 2019, interest from 3.0 to 5.0 percent	7,090	7,090
$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, 2014 was 3.1 percent). Partially refunded $11,825 on July 25, 2013 with the 2013 Electric Revenue Refunding Bonds	41,925	53,750
$79,080 2013 Electric Revenue Refunding Series A Bonds: fixed rate bonds due in annual principal installments from $795 to $12,685 through October 1, 2043, interest from 3.0 to 5.25 percent	76,560	-
Total electric revenue bonds payable	597,580	576,430
Unamortized bond premium	10,434	7,189
Total electric revenue bonds payable, including bond premium	608,014	583,619
Less current portion of revenue bonds payable	(14,920)	(20,685)
Total long-term electric revenue bonds payable	$ 593,094	$ 562,934

Revenue bonds annual debt service requirements to maturity as of June 30, 2014 are as follows (in thousands):

	2015	2016	2017	2018	2019	2020-2024	2025-2029	2030-2034	2035-2039	2040-2044	Total
Principal	$ 14,920	$ 15,825	$ 13,320	$ 13,795	$ 14,445	$ 80,575	$ 97,715	$120,155	$149,040	$ 77,790	$ 597,580
Interest	$ 26,445	$ 25,770	$ 25,114	$ 24,530	$ 23,887	$110,688	$ 91,628	$ 68,298	$ 38,047	$ 4,844	439,251
Total	$ 41,365	$ 41,595	$ 38,434	$ 38,325	$ 38,332	$191,263	$189,343	$188,453	$187,087	$ 82,634	$1,036,831

The Utility's bond indentures require the Utility to maintain a minimum debt service coverage ratio, as defined by the bond covenants of 1.10. The Utility's debt service coverage ratio was 2.16 and 2.73 at June 30, 2014 and 2013, respectively. This debt (revenue bonds) is backed by the revenues of the Utility.

2013 ELECTRIC REVENUE REFUNDING BONDS

On July 25, 2013, $79,080, including premium, of 2013 Electric Revenue Refunding Series A Bonds and $780 of Taxable Electric Revenue Series B Bonds were sold with an all-in true interest cost of 4.50%. The bond proceeds were deposited in escrow accounts to: prepay the outstanding obligation of $42,661 to the City of Corona related to the Clearwater Power Plant; refund $13,975 of the 2008 Electric Refunding/Revenue Series A Bonds, $11,775 of the 2008 Electric Refunding/Revenue Series C Bonds, and $11,825 of the 2011 Electric Revenue Series A Bonds; and to pay a portion of the termination cost associated with the interest rate swaps allocated or related to the refunded portions of the applicable bonds. This cost has been recorded on the Statements of Net Position as a deferred outflow of resources and will be amortized over the term of the new bonds. This refunding resulted in an increase in debt service payments of $10,962 over the next 30 years and an economic gain of $2,961. Interest on the 2013 Series A bonds is payable semi-annually on April 1 and October 1, commencing October 1, 2013. Principal is due in annual installments from $795 to $12,685 through October 1, 2043. The rate of interest varies from 3% to 5.25% per annum. 2013 Series B bonds, with an interest rate of 0.5%, were due and paid in one installment of $780 on October 1, 2013.

LETTERS OF CREDIT

The Utility's 2008 Electric Revenue Bonds (Series A and C) require an additional layer of security between the Utility and the purchaser of the bonds. The 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:

Debt Issue	LOC Provider	LOC Expiration Date	Annual Commitment Fee
2008 Electric Refunding/Revenue Bonds Series A	Barclays Bank, PLC	2017	0.275%
2008 Electric Refunding/Revenue Bonds Series C	Bank of America, N.A.	2017	0.390%

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 over a 5-year period. The Utility would be required to pay $31,213 a year for 5 years (assuming a 12 percent interest rate) if $112,515 of 2008 Electric Revenue Bonds (Series A and C) were "put" and not resold. No amounts have ever been drawn against the two LOCs due to a failed remarketing.

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

INTEREST RATE SWAPS ON REVENUE BONDS

The 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, 2014 is as follows:

	Notional Amount	Fair Value as of 6/30/2014	Change in Fair Value for Fiscal Year
2008 Electric Refunding/Revenue Bonds Series A	$ 68,525	$ (8,845)	$ 800
2008 Electric Refunding/Revenue Bonds Series C	$ 41,975	$ (6,646)	$ 410
2011 Electric Refunding/Revenue Bonds Series A	$ 41,925	$ (6,617)	$ 411

Objective: In order to lower borrowing costs as compared to fixed-rate bonds, the 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 Utility pays the counterparty a fixed payment and receives a variable payment computed as 62.68% 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, 2014, 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	(0.42414%)	(0.42543%)	(0.24925%)
Net interest rate swap payments		2.68686%	2.77857%	2.95175%
Variable-rate bond coupon payments		0.35041%	0.34837%	0.14338%
Synthetic interest on bonds		3.03727%	3.12694%	3.09513%

Fair value: As of June 30, 2014, in connection with all swap agreements, the transactions had a total negative fair value of ($22,108). Because the coupons on the 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, 2014, the 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 A- 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, 2014, there is no requirement for collateral posting for any of the outstanding swaps.

Basis risk: As noted above, the swaps expose the 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 Utility if either counterparty's credit quality falls below "BBB-" as issued by S&P. The 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 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, 2014, 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.

	Variable-Rate Bonds			
Fiscal Year Ending June 30,	Principal	Interest	Interest Rate Swaps, Net	Total
2015	$ -	$ 453	$ 4,299	$ 4,752
2016	-	453	4,299	4,752
2017	-	453	4,299	4,752
2018	-	453	4,299	4,752
2019	6,375	433	4,125	10,933
2020-2024	42,075	1,771	17,085	60,931
2025-2029	39,630	1,134	11,699	52,463
2030-2034	45,985	481	5,593	52,059
2035-2037	20,375	26	297	20,698
Total	$ 154,440	$ 5,657	$ 55,995	$ 216,092

NOTE 5. 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 8 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 Utility's electric revenue and refunding bonds require debt service reserves that equate to the maximum annual debt service required in future years and bond service reserves of three months interest and nine months principal due in the next fiscal year. Variable rate revenue and refunding bonds require 110% of the monthly accrued interest to be included in the reserve. Active electric revenue bonds requiring reserves are issues 2004A and 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 6. 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 the 2013-14 and 2012-13 fiscal years, the Utility paid


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NOTE 6. JOINTLY-GOVERNED ORGANIZATIONS (CONTINUED)

approximately $17,440 and $16,171, respectively, to SCPPA under various take-or-pay contracts that are described in greater detail in Note 8. 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 7. JOINTLY-OWNED UTILITY PROJECT – SONGS

The City has a 1.79% undivided ownership interest in Units 2 and 3 of SONGS, located south of the City of San Clemente in northern San Diego County; however, on June 7, 2013, SCE announced, in a press release, its plan to retire Units 2 and 3 of SONGS permanently. Consequently, the units are no longer a source of supply for the 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).

Units 2 and 3 of SONGS became operational on October 9, 1983 and April 1, 1984, respectively. The Utility's share of the original construction costs plus subsequent ongoing betterments was approximately $165 million, which was financed mainly through revenue bonds.

The capacity previously available to the City from SONGS Units 2 and 3 was 19.2 MW and 19.3 MW, respectively. SONGS has a nominal net generating capability of 2,150 MW. The other owners are SCE, with a 78.21% interest (including the 3.16% interest it acquired from the City of Anaheim in 2006), and San Diego Gas & Electric Company (SDG&E), with a 20.00% 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. The three-member SONGS Board of Review approved the budget for capital expenditures and operating expenses. The City and the two other owners each had one representative on that board. The participation agreement provided that each owner was entitled to its proportionate share of benefits of, and paid its proportionate share of costs and liabilities incurred by SCE for, construction, operation and maintenance of the project; each owner's obligation was several, and not joint or collective. The City's influence to control or manage SONGS was limited at times because the City does not have a controlling interest.

In 2005, the California Public Utilities Commission (CPUC) authorized a project to install four new steam generators in Units 2 and 3 at SONGS and remove and dispose of the predecessor generators. SCE completed the installation of these steam generators in 2010 and 2011 for Units 2 and 3, respectively. The 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 Nuclear Regulatory Commission (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.

NOTE 7. JOINTLY-OWNED UTILITY PROJECT – SONGS (CONTINUED)

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.

The current plant site easement for SONGS terminates on May 12, 2024 and would need to be extended in order for the plant to be decommissioned and the site restored.

NRC Proceedings. As part of the NRC's review of the SONGS outage and proceedings related to the possible restart of Unit 2, the NRC appointed an Augmented Inspection Team to review SCE's performance. In December 2013, SCE received a final NRC Inspection Report that identified a violation for the failure to verify the adequacy of the thermal-hydraulic and flow-induced vibration design of the Unit 3 replacement steam generators. In January 2014, SCE provided a response to the NRC Inspection Report stating that Mitsubishi Heavy Industries (MHI), as contracted by SCE to prepare the SONGS replacement steam generator design, was the party responsible for performing the verification and checking of the design of the steam generators. On September 13, 2013, the NRC issued a Notice of Nonconformance for MHI's flawed computer modeling in the design of the replacement steam generators. On October 17, 2013, MHI submitted a reply to the Notice of Non-Conformance, indicating that MHI did not contest the asserted noncompliance and that corrective action had been taken.

Because SONGS has ceased operation, NRC inspection oversight of SONGS will now be continued through the NRC's Decommissioning Power Reactor Inspection Program to verify that decommissioning activities are being conducted safely, that spent fuel is safely stored onsite or transferred to another licensed location, and that the site operations and licensee termination activities conform to applicable regulatory requirements, licensee commitments and management controls.

Nuclear Decommissioning. As a result of SCE's decision to permanently retire SONGS Units 2 and 3, SCE has begun the decommissioning phase of the plant. The process of decommissioning a nuclear power plant is governed by NRC regulations. The regulations categorize the decommissioning activities into three phases: initial activities, major decommissioning and storage activities, and license termination. Initial activities include providing notice of permanent cessation of operations (accomplished on June 12, 2013) and notice of permanent removal of fuel from the reactor vessels (provided by SCE to the NRC on June 28 and July 22, 2013 for Units 3 and 2, respectively). Within two years after the announcement of retirement, SCE, as the operating licensee must submit a post-shutdown decommissioning activities report, an irradiated fuel management plan and a site-specific decommissioning cost estimate. SCE currently estimates that it will provide the other initial activity phase plans and cost estimates to the NRC by the end of 2014.

SCE has prepared a draft decommissioning plan, an environmental evaluation and an updated cost estimate to decommission the San Onofre nuclear plant. The draft plan, called a Post-Shutdown Decommissioning Activities Report (PSDAR), spells out the timetable for major decommissioning work expected to begin in early 2016 and indicates adequate funds exist to pay for the work. SCE estimates that it will cost $4.4 billion to safely complete the 20-year decommissioning of San Onofre.

Replacement Power Costs. During the outage, the Utility had procured replacement power to serve its customers' requirements. These costs were in addition to the usual approximate $11.5 million in operating and maintenance expenses paid annually during normal operations. Replacement power costs incurred by the Utility as a result of the outage (commencing on January 31, 2012 for Unit 3 and March 5, 2012 for Unit 2) through June 30, 2013 were approximately $13.2 million and are reflected as regulatory assets on the Statements of Net Position. During fiscal year 2014, the Utility paid for its share of ongoing operating costs and replacement power related to SONGS from current rate revenue.

Contractual Matters. The replacement steam generators for Units 2 and 3 were designed and manufactured by 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 million and excludes consequential damages, defined to include "the cost of replacement power." The limitations are subject to certain exceptions.

There are insurance policies for both property damage and accidental outage issued by Nuclear Electric Insurance Limited (NEIL), and SCE has notified NEIL of claims under the two policies. The City is a named insured on the SCE insurance policies covering SONGS and will assist SCE in pursuing claims recoveries from NEIL, but there is no assurance that the Utility will recover all or any of its applicable costs under these arrangements. To the extent that any third-party recoveries are made, they will reduce cost to the Utility.

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 initiated a 90-day dispute resolution process under the purchase agreement. Such arbitration will be conducted before the International Court of Arbitration (the ICC). On July 18, 2013, the City filed a lawsuit against MHI for breach of contract, negligence and misrepresentation in San Diego County Superior Court. On July 24, 2013, MHI moved the lawsuit to the United States District Court for the Southern District of California, and on August 8, 2013, MHI moved to stay the proceeding pending resolution of the dispute resolution process involving MHI and SCE arising from the contract for the purchase and sale of the steam generators. In October 2013, after a prescribed 90-day waiting period from the service of an earlier notice of dispute, SCE initiated an arbitration proceeding against MHI seeking damages stemming from the failure of the replacement steam generators. In late December 2013, MHI answered and filed a counter-claim against SCE. On March 14, 2014, the Federal District court granted MHI's motion to stay the City's proceeding, but ordered that the City participate in the SCE/MHI arbitration. SCE, SDGE, the City and MHI have all stipulated that the City and SDGE shall participate in the SCE/MHI arbitration before the ICC. No arbitration date has been set.

As a result of the decision by SCE to permanently retire Units 2 and 3 of SONGS prior to the expiration of the NRC licenses, the Utility expects to incur certain costs resulting from the early termination of long-term uranium fuel supply contracts. On November 12, 2013, Uranium One Inc. served a Demand for Arbitration on SCE, SDG&E and the City, seeking an award of damages in the approximate amount of $12.5 million. Uranium One, Inc. asserts damages from a purchase agreement to deliver certain amounts of uranium concentrates in 2011, 2012 and 2013. On April 25, 2014, Energy Resources of Australia, Ltd. and Rossing Uranium Ltd. served a Demand for Arbitration on SCE, asserting similar claims as Uranium One Inc. and seeking an award of damages in the approximate amount of $19.5 million. No arbitration dates have been set and the Utility cannot estimate the outcomes of these pending claims at this time.

NOTE 8. COMMITMENTS

TAKE-OR-PAY CONTRACTS

The Utility has entered into a power purchase contract with Intermountain Power Agency (IPA) for the delivery of electric power. The 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 located in central Utah. The contract expires in 2027 and the debt fully matures in 2024.

The contract constitutes an obligation of the Utility to make payments solely from operating revenues. The power purchase contract requires the 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.

The Utility is a member of SCPPA, a joint powers agency (see Note 6). 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 Utility participates in projects developed by SCPPA, it has entered into Power Purchase or Transmission Service Agreements, entitling the Utility to the power output or transmission service, as applicable, and the 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 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	5.4 percent	12.3 MW	2017	2030
Southern Transmission System	10.2 percent	244.0 MW	2027	2027
Hoover Dam Uprating	31.9 percent	30.0 MW	2017	2017
Mead-Phoenix Transmission	4.0 percent	18.0 MW	2020	2030
Mead-Adelanto Transmission	13.5 percent	118.0 MW	2020	2030

NOTE 8. COMMITMENTS (CONTINUED)

As part of the take-or-pay commitments with IPA and SCPPA, the 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.

Outstanding debts associated with the take-or-pay obligations have variable interest rates for the Palo Verde Nuclear Generating Station Project and portions of the Mead Phoenix and Mead Adelanto Projects. The remaining projects have fixed interest rates which range from 0.35 percent to 6.13 percent. The schedule below details the amount of principal and interest that is due and payable by the 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	Palo Verde Nuclear Generating Station	Southern Transmission System	Hoover Dam Uprating	Mead-Phoenix Transmission	Mead-Adelanto Transmission	All Projects
2015	$ 14,786	$ 669	$ 8,310	$ 703	$ 269	$ 3,087	$ 27,824
2016	22,127	672	8,364	701	269	3,013	35,146
2017	11,650	675	8,182	701	262	2,952	24,422
2018	16,935	679	8,020	699	258	2,910	29,501
2019	18,827	-	7,927	-	257	2,882	29,893
2020-2024	55,421	-	40,163	-	443	4,995	101,022
2025-2029	-	-	14,334	-	-	-	14,334
Total	$ 139,746	$ 2,695	$ 95,300	$ 2,804	$ 1,758	$ 19,839	$ 262,142

In addition to debt service, the 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, 2014 and 2013, 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
2014	$ 24,466	$ 2,416	$ 3,296	$ 104	$ 50	$ 312	$ 30,644
2013	$ 26,445	$ 2,528	$ 2,405	$ 97	$ 41	$ 338	$ 31,854

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

The Utility has become a Participating Transmission Owner (PTO) 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 Utility receives reimbursement for, its transmission revenue requirements (TRR), including the costs associated with these three transmission projects.

HOOVER UPRATING PROJECT

In December 2011, the Hoover Power Allocation Act (the Hoover Act) was enacted into law. It provides for the extension of the existing Hoover contract for an additional 50 years from 2017 to 2067. The legislation required current Hoover Dam contractors to relinquish five percent of their allocations to be used to provide allocations to potential new Hoover contractors. The impact to the Utility is a reduction of about 1.5 MW in capacity and associated energy. Under the Hoover Act, the new Hoover contractors would be required to pay their proportionate share of the cost associated with the Lower Colorado River Multi-Species Conservation

Program and Uprating Program. Any capacity and energy not contracted for by new Hoover contractors will be reallocated to the existing contractors along with any refunds due associated with the Multi-Species Conservation Program.

In March 2014, the 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 is a component of the cost of power and energy payable by Hoover contractors, which includes SCPPA participants that receive power from the Hoover Power Project under agreements with the Western Area Power Administration. Because Bureau Debt bears interest at rates that are substantially higher than current market interest rates, the Utility elected to prepay the debt in order to realize savings on power costs in the future. The Utility's share of the debt was $1.5 million and is recorded on the Statements of Net Position as unamortized purchased power, to be amortized over the remaining term of the project.

POWER PURCHASE AGREEMENTS

The Utility has one firm power purchase agreement (PPA) with Bonneville Power Administration (BPA) for the purchase of capacity, 50 MW during the summer months and 13 MW during the winter months, beginning April 30, 1996, for 20 years. Effective May 1, 1998, these summer and winter capacity amounts increased to 60 MW and 15 MW, respectively, for the remainder of the agreement. On January 29, 2013, the Utility revised the delivery and return portion of the agreement to allow for a flat 40 MW of delivery during May and June through calendar years 2013, 2014 and 2015. The agreement with BPA will terminate on May 1, 2016.

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 ($375 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 September 10, 2013, the Act limits liability from third-party claims to approximately $13.6 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 Utility's interest in Palo Verde and ownership in SONGS, the Utility would be responsible for a maximum assessment of $25.2 million, limited to payments of $3.8 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% by December 31, 2020 in three stages: average of 20% of retail sales during 2011-2013; 25% of retail sales by December 31, 2016; and 33% 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 Utility's RPS Procurement plan implementing the new RPS mandates on May 3, 2013 and May 14, 2013, respectively. It is expected that the Utility will be able to meet the new mandates with new resource procurement actions as outlined in the Utility's RPS Procurement Plan. For calendar year 2013, renewable resources provided 24% of retail sales requirements.

In an effort to increase the share of renewables in the Utility's power portfolio, the Utility entered into PPAs with various entities described below on a "take-and-pay" basis. The contracts in the following tables were executed as part of compliance with this standard.

NOTE 8. COMMITMENTS (CONTINUED)

Long-term renewable PPAs in operation (in thousands):

Supplier	Type	Maximum Contract [1]	Contract Expiration	Estimated Annual Cost For 2015
Salton Sea Power LLC	Geothermal	46.0 MW	5/31/2020	$ 23,675
Wintec	Wind	1.3 MW	12/30/2018	211
WKN Wagner	Wind	6.0 MW	12/22/2032	1,113
Total		53.3 MW		$ 24,999

Long-term renewable PPAs with expected delivery:

Supplier	Type	Maximum Contract [1]	Expected Delivery	Energy Delivery No Later Than	Contract Term In Years
CalEnergy	Geothermal	86.0 MW	2/11/2016	2/11/2016	25
AP North Lake	Photovoltaic	20.0 MW	6/30/2015	12/31/2015	25
FTP Solar					
Summer Solar	Photovoltaic	10.0 MW	6/30/2016	12/31/2016	25
Antelope Big Sky Ranch	Photovoltaic	10.0 MW	6/30/2016	12/31/2016	25
First Solar	Photovoltaic	14.0 MW	12/31/2015	6/30/2016	20
Recurrent Clearwater	Photovoltaic	14.9 MW	Delayed	12/31/2015	20
Dominion Columbia II	Photovoltaic	11.1 MW	12/31/2014	12/31/2015	20
Cabazon Wind	Wind	39.0 MW	1/1/2015	12/31/2015	10
Solar Star	Photovoltaic	7.3 MW	9/30/2015	12/31/2015	25
Total		212.3 MW			

[1] All contracts are contingent on energy production from specific related generating facilities. The Utility has no commitment to pay any amounts except for energy produced on a monthly basis from these facilities.

On May 20, 2003, the 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 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 starting with 20 MW in 2016 and increasing to 40 MW in 2019 and 86 MW in 2020. The PPA is expected to provide 7.5%, 15% and 30% of the City's total power demand in 2016, 2019, and 2020, respectively. The price under the agreement will be $72.85 per megawatt-hour (MWh) in calendar year 2016 and escalate at 1.5% annually for the remaining term of the agreement. Similar to other renewable PPAs, the 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% 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 $2.7 million per year for the agreement's remaining term. This increase in price for fiscal year 2014 is recorded in the Statements of Net Position as unamortized purchased power in the amount of $2.0 million, to be amortized over the term of the CalEnergy PPA.

On November 10, 2006, the Utility entered into a second renewable PPA with Wintec Energy, Ltd (Wintec) for wind generation capacity of up to 8.0 MW on their proposed Wintec Facility II Wind Turbine Project. The contract term is for 15 years, expiring November 10, 2021. The developer encountered challenges in finding suitable wind turbines to complete the project. Due to the delay of the proposed Wintec Facility II Wind Turbine Project, on February 7, 2012, Wintec entered into an assignment agreement with WKN Wagner, LLC (WKN) for the purpose of assigning to WKN all of Wintec's right, title, and interest in the renewable PPA dated November 10, 2006. The Utility agreed to the assignment and entered into a new PPA with WKN under the same commercial terms and conditions as in the original agreement with Wintec, except that the term has been extended to 20 years, instead of 15. WKN completed the project development timely, and the project became commercially operational on December 22, 2012 and is expected to contribute 1% of the City's retail load requirements at a levelized cost of $73 per MWh. The Utility does not expect to receive more than 1.3 MW from Wintec per the original contract which expires in December 2018.

On October 16, 2012, the 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 project is expected to become commercially operational by June 30, 2015, but in no event later than December 31, 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 January 8, 2013, the Utility entered into two 25-year PPAs for a combined total of 20 MW of solar photovoltaic energy generated by two facilities to be built by Silverado Power, which was later acquired by FTP Solar LLC, in the City of Lancaster, California. The two projects are referred to as Antelope Big Sky Ranch and Summer Solar, each rated at 20 MW. The Utility will have a 50% share of the output from each project through SCPPA. The projects were expected to become commercially operational by January 1, 2015, but in no event later than December 31, 2015. The Utility's share from the two projects is 55,000 MWh of renewable energy per year. On April 1, 2014, the City Council approved the first amendment to the PPAs, which postponed the outside commercial operation date for each project from December 31, 2015 to December 31, 2016, with the most significant change being a reduction in a price for energy and environmental attributes from $95.30 per MWh to $71.25 per MWh over the term of the agreement.

On September 19, 2013, the Utility entered into a 20-year PPA 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 Utility will have a 70% share of the output from the project through SCPPA. The project is expected to become commercially operational at the end of 2015, but no later than June 30, 2016. The 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 Utility entered into two 20-year PPAs for a combined 26 MW of solar photovoltaic energy generated by two facilities to be built by Recurrent Energy in Kern County, California. The two projects being developed are referred to as Clearwater and Columbia II Solar Photovoltaic Projects, with a nameplate capacity of 20 MW and 15 MW, respectively. The Utility will have a 74.29% share of the output from the projects through SCPPA. The Utility's share from the two projects is approximately 65,000 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 agreements. Both projects were originally expected to become commercially operational at the end of 2014. However, the Clearwater project has encountered significant delays and is no longer expected to be commercially operational by that time. The Utility will be receiving liquidated damages as a result. The Columbia II project development is on schedule and still expected to be commercially operational by the end of 2014. On March 14, 2014 a Consent and Agreement was entered into by SCPPA consenting to the transfer of ownership of the Columbia II project to Dominion Solar. Upon completion of the permitting process by Recurrent Energy, a similar transfer to Dominion Solar is expected for the Clearwater project.

On December 6, 2013, the 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 is currently purchasing the output of the facility through December 2014. At the expiration of SCE's contract, the project will need to enter into new interconnection and generation agreements with the CAISO and SCE, and the developer is on schedule to implement the transition to the Utility. Delivery under the PPA will commence 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.

On March 11, 2014, the 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 is expected to become

NOTE 8. COMMITMENTS (CONTINUED)

commercially operational by June 1, 2015 and is expected to generate approximately 15,000 MWh of renewable energy per year. On September 5, 2014, SunPower, the parent company of Solar Star, requested an extension of the date of commercial operation to September 30, 2015. The all-in price for energy, capacity and environmental attributes is $81.30 per MWh, escalating at 1.5% annually.

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 Utility's free allocation of GHG allowances is expected to be sufficient to meet the Utility's direct GHG compliance obligations. At times, the Utility may have allocated allowances in excess of its compliance obligations that can be sold into the CARB quarterly auctions. As of June 30, 2014 and 2013, the Utility received $2,769 and $381, respectively, in proceeds related to the sale of the GHG allowances and is included on the Statements of Revenues, Expenses and Changes in Net Position as other operating revenue. The Utility has established a restricted cash reserve in the amount of $3,150 and $381 as of June 30, 2014 and 2013, respectively, to comply with regulatory restrictions and governing requirements related to the use of the GHG proceeds. This reserve is included in restricted cash and cash equivalents on the Statements of Net Position. As of June 30, 2014 and 2013, the Utility also had purchased $1,202 and $507, respectively, in GHG allowances which can be used in future periods for GHG compliance regulations. These amounts are recorded as inventory in the Statements of Net Position.

CONSTRUCTION COMMITMENTS

As of June 30, 2014, the Utility had major commitments (encumbrances) of approximately $11,977 with respect to unfinished capital projects, of which $11,424 is expected to be funded by bonds and $553 funded by rates.

FORWARD PURCHASE/SALE AGREEMENTS

In order to meet summer peaking requirements, the 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, 2014, the Utility has net commitments for fiscal year 2015 and thereafter, of approximately $33,663, with a market value of $33,673.

NOTE 9. LITIGATION

The Utility is a defendant in various lawsuits arising in the normal course of business. Present lawsuits and other claims against the Utility are incidental to the ordinary course of operations of the 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 Utility.

Contractual and litigation matters of the Utility relating to SONGS are contained in Note 7.

CALIFORNIA ENERGY CRISIS SETTLEMENT

During the California Energy Crisis of 2001-2002, the Utility made numerous power sales into the California centralized markets. Due to financial problems experienced by numerous market participants, notably Pacific Gas & Electric (PG&E) and the California Power Exchange (Cal PX), who filed for Chapter 11 bankruptcy in 2001, the Utility was not paid for many of these transactions. On June 4, 2008, the FERC approved a settlement agreement between the Utility and numerous California entities, including all of the IOUs and the California Attorney General, under which the Utility was paid all of its unpaid receivables, plus interest, minus $1.27 million in refunds. The net payout to the Utility was $3.7 million (including all unpaid receivables, including interest and its deposit with the Cal PX, minus $269 thousand paid to the City of Banning for transactions made on its behalf by the Utility). Under the settlement, the Utility may receive additional distributions of refunds from other sellers. The Utility also may be responsible for paying its allocated portion, as determined by FERC, of payments due to other sellers for any Emission Offset, Fuel Cost Allowance, or Cost Offset associated with sales by such other sellers during the energy crisis. It is not possible at this time to estimate the net effect of any such future distributions to or payments by the Utility.

DAIRY COW LITIGATION

In 2002 and 2003, the Los Angeles Department of Water and Power (LADWP) received a number of claims from dairies and dairy farmers located in Utah and California. The claims generally allege that since 1987, "stray voltage" emitted from the Intermountain Power Project (IPP) facilities through the ground and ground water damaged dairy herds, including causing higher than normal death rates, a reduction in milk production and impairment to the cows' immune systems. LADWP, as operating agent for IPA, denied all of the claims.

In February 2005, claimants filed a lawsuit in the Utah state court, entitled *Gunn Hill Dairy Properties, LLC, et al. v. Los Angeles Department of Power, et al.,* Case No. 050700157, naming SCPPA (the entity financing the Southern Transmission System's (STS) facilities), LADWP (the operator of the STS facilities), the IPA (the owners of the STS facilities), and others as defendants. The plaintiff dairies seek compensatory damages in excess of $515 million plus punitive damages. In November 2013, a mistrial was declared in the case relating to six of the plaintiff dairies. Subsequent to the mistrial, these six plaintiff dairies filed a motion for sanctions, including the request for a default judgment in favor of the six plaintiffs. SCPPA, LADWP, IPA and other defendants have filed an opposition to that motion, asserting that there is no basis for the requested remedy. Separate trials for two other plaintiff dairy groups have not yet commenced.

Electrical tests performed by LADWP's experts reveal no current or voltage attributable to the IPP facilities on the plaintiff dairies' farms, and SCPPA, LADWP, and the IPA believe that their claims are without merit. In the event that damages are awarded to the plaintiff dairies against the IPA, any part of the award not otherwise covered by insurance may be apportioned among utilities that purchase IPP capacity in accordance with their entitlement shares.

NOTE 10. EXTRAORDINARY ITEM

On June 7, 2013, SCE announced its decision to permanently retire SONGS Units 2 and 3. Consequently, the units are no longer a source of supply for the Utility. As a result, SONGS Units 2 and 3 with a net book value of $29,075 are considered impaired and written off from Utility Plant assets on the Statements of Net Position. The associated nuclear fuel with a net book value of $10,149 and nuclear materials inventory with a net book value of $ 2,035 are also considered impaired and written off from the Statements of Net Position. The total loss of $41,259 is reported as an extraordinary item on the Statements of Revenues, Expenses and Changes in Net Position for the year ended June 30, 2013.

NOTE 11. ACCOUNTING CHANGE

Effective July 1, 2012, the accompanying financial statements reflect the implementation of GASB Statement No. 63, *Financial Reporting of Deferred Outflows of Resources, Deferred Inflows of Resources, and Net Position* (GASB 63), and GASB Statement No. 65, *Items Previously Reported as Assets and Liabilities* (GASB 65). Significant impacts of GASB 63 include changing the title of the Balance Sheets to Statements of Net Position, changing the title of equity section to net position and reformatting the Statements of Net Position to add separate sections for deferred outflows of resources and deferred inflows of resources. Significant impacts of GASB 65 include reclassifying as deferred outflows of resources and deferred inflows of resources certain balances that were previously reported as assets and liabilities.

Electric

KEY HISTORICAL OPERATING DATA

KEY HISTORICAL OPERATING DATA

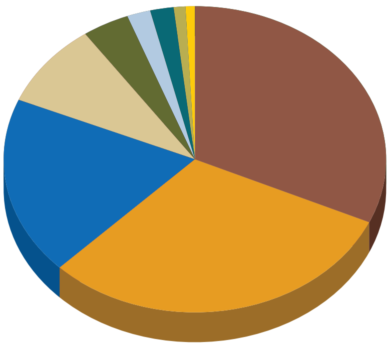
FISCAL YEAR	2013/14	2012/13	2011/12	2010/11	2009/10
POWER SUPPLY (MWH)					
Nuclear					
San Onofre	0	0	191,900	284,900	240,000
Palo Verde	99,900	102,300	101,100	102,000	96,300
Coal					
Intermountain Power	802,100	754,900	799,700	895,600	1,068,500
Deseret	0	0	0	0	187,400
Hoover (Hydro)	33,200	32,500	35,300	32,900	30,000
Gas					
Springs	1,300	5,500	2,300	3,100	1,400
RERC	64,400	77,700	39,400	34,500	11,500
Clearwater	20,600	24,000	17,000	9,700	0
Renewable Resources	423,800	444,300	472,300	385,700	354,900
Other purchases	899,200	937,500	620,000	464,200	276,500
Exchanges In	93,300	95,800	75,200	92,200	92,700
Exchanges Out	(158,300)	(134,900)	(133,500)	(176,100)	(156,200)
Total	2,279,500	2,339,600	2,220,700	2,128,700	2,203,000
System peak (MW)	577.9	591.7	581.2	579.7	560.3
Number of meters as of year end					
Residential	96,820	96,207	95,988	95,676	95,258
Commercial	10,558	10,337	10,425	10,185	10,073
Industrial	898	894	822	908	916
Other	82	87	86	86	88
Total	108,358	107,525	107,321	106,855	106,335
Millions of kilowatt-hours sales					
Residential	700	726	688	666	701
Commercial	421	419	413	400	406
Industrial	997	1,003	969	912	906
Other	30	31	31	31	32
Subtotal	2,148	2,179	2,101	2,009	2,045
Wholesale	4	14	2	7	44
Total	2,152	2,193	2,103	2,016	2,089
ELECTRIC FACTS					
Average annual kWh per residential customer	7,239	7,547	7,208	7,006	7,397
Average price (cents/kWh) per residential customer	$16.00	$16.27	$16.07	$16.17	$15.31
Debt service coverage ratio (DSC)[2]	2.16	2.73	2.24	2.21	2.75
Operating income as a percent of operating revenues	19.5%	24.0%	22.1%	18.9%	23.5%
Employees[1]	463	460	453	449	427

[1]Approved positions.

[2]For FY 10/11 and thereafter, interest expense used to calculate DSC is net of federal subsidy on Build America Bonds.

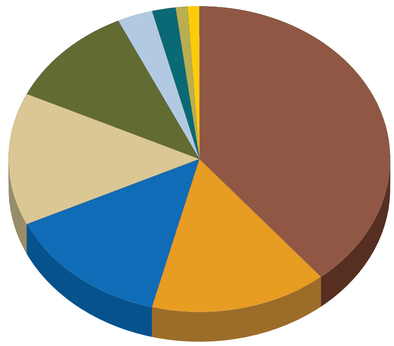
2013/2014 ELECTRIC REVENUE AND RESOURCES

Source of Revenue



- Residential Sales 32¢
- Industrial Sales 31¢
- Commercial Sales 19¢
- Transmission Revenue 9¢
- Other Revenue 4¢
- Public Benefit Programs 2¢
- Investment Income 2¢
- Other Sales 1¢
- Wholesale Sales < 1¢

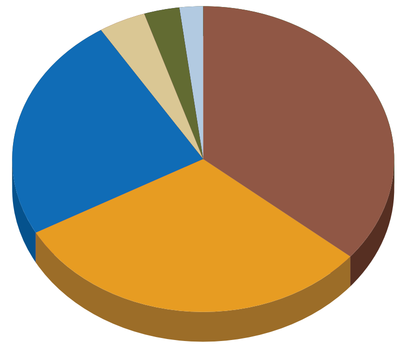
Distribution of Revenue



- Production 39¢
- Transmission 15¢
- Distribution 14¢
- Debt Service 14¢
- Transfers to the City's General Fund* 11¢
- Additional Reserves 3¢
- Public Benefit Programs 2¢
- Unamortized Purchased Power 1¢
- Additions and Replacements to the System 1¢

** Based on transfer of 11.5% of fiscal year 2012/2013 gross operating revenues including adjustments.*

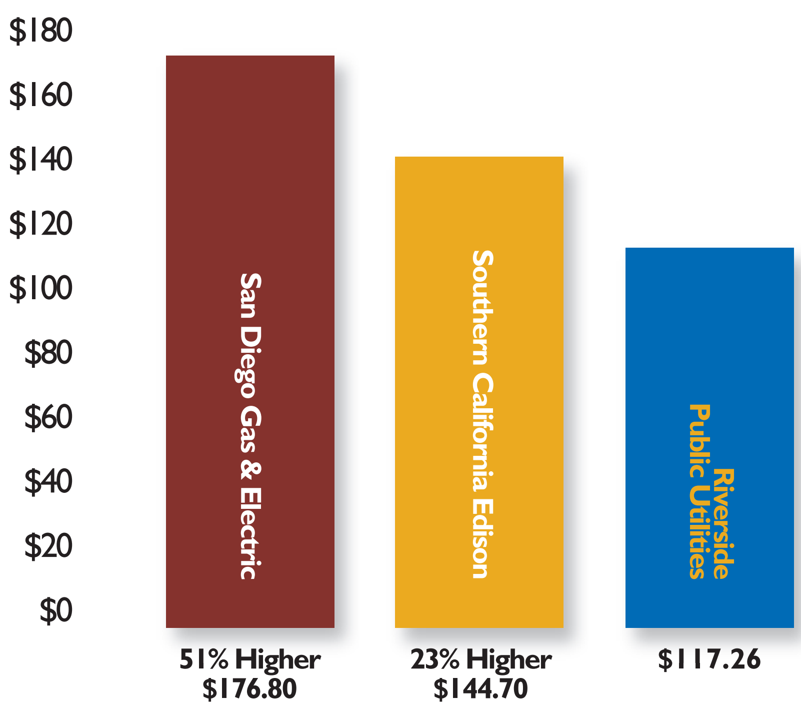
Energy Resources



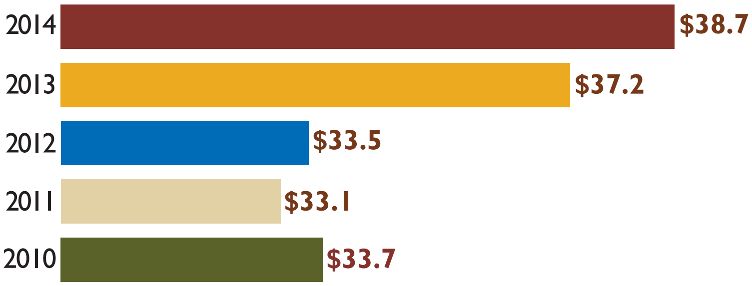
- Other Purchases 36%
- Coal 31%
- Renewables 24%
- Nuclear 4%
- Gas 3%
- Hydropower 2%

** Energy Resources are based on calendar year 2013 as filed with the California Energy Commission.*

ELECTRIC RATE COMPARISON - 750 KWH PER MONTH (AS OF JUNE 30, 2014)

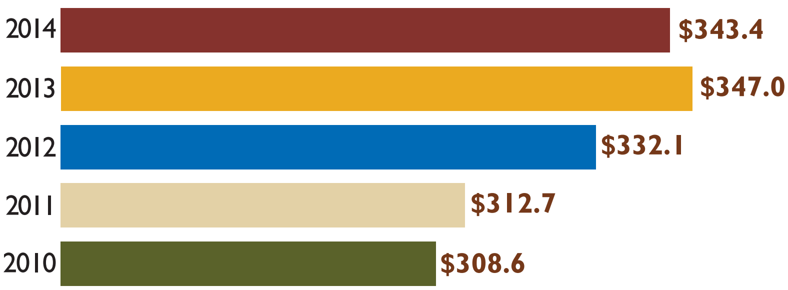


GENERAL FUND TRANSFER (IN MILLIONS)

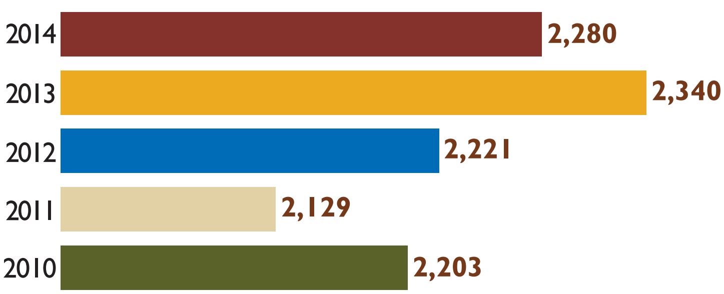


NUMBER OF METERS AT YEAR END

TOTAL OPERATING REVENUE (IN MILLIONS)



PRODUCTION (IN MILLION KILOWATT-HOURS)



PEAK DAY DEMAND (IN MEGAWATTS)

ELECTRIC FACTS AND SYSTEM DATA

Established	1895
Service Area Population	313,975
Service Area Size (square miles)	81.5
System Data:	
Transmission lines (circuit miles)	98.6
Distribution lines (circuit miles)	1,327
Number of substations	14
2013-2014 Peak day (megawatts):	578
Highest single hourly use: 09/05/2013, 4 pm, 98 degrees	
Historical peak (megawatts): 08/31/2007, 4 pm, 106 degrees	604

Bond Ratings

Fitch Ratings	AA-
Standard & Poor's	AA-
Debt Derivative Profile Score on Swap Portfolio (1 representing the lowest risk and 4 representing the highest risk)	2