10 CFR 50.71(b)
10 CFR 72.80(b)

aps

Palo Verde
Nuclear Generating Station
PO Box 52034
Phoenix, Arizona 85072-2034
Mail Station 7636

102-07160-TNW/TMJ
December 9, 2015

ATTN: Document Control Desk
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

Dear Sirs:

Subject: **Palo Verde Nuclear Generating Station (PVNGS)**
Units 1, 2, and 3
Docket Nos. STN 50-528/529/530
Submittal of Annual Financial Reports

Pursuant to 10 CFR 50.71(b) and 10 CFR 72.80(b), enclosed please find the 2014 Annual Financial Reports for the Participants who jointly own PVNGS and do not file a Form 10-Q with the Securities and Exchange Commission or a Form 1 with the Federal Energy Regulatory Commission. These Participants are Salt River Project, Southern California Public Power Authority and Los Angeles Department of Water and Power.

The remaining Participants who jointly own PVNGS file a Form 10-Q with the Securities and Exchange Commission or a Form 1 with the Federal Energy Regulatory Commission and therefore do not have to file an Annual Financial Report in accordance with 10 CFR 50.71(b) or 10 CFR 72.80(b). These Participants are El Paso Electric Company, Arizona Public Service Company, Southern California Edison Company and Public Service Company of New Mexico.

No commitments are being made to the NRC by this letter.

Should you need further information regarding this submittal, please contact Thomas N. Weber, Regulatory Affairs Department Leader, at (623) 393-5764.

Sincerely,

Thomas N. Weber

Thomas N. Weber
Department Leader, Regulatory Affairs

TNW/TMJ/af

Enclosure: PVNGS 2014 Annual Financial Reports
Salt River Project, Southern California Public Power Authority,
Los Angeles Department of Water and Power

cc:	M. L. Dapas	NRC Region IV Regional Administrator
	M. M. Watford	NRC NRR Project Manager
	C. A. Peabody	NRC Acting Senior Resident Inspector for PVNGS

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NRR

Enclosure

PVNGS 2014 Annual Financial Reports

Salt River Project, Southern California Public Power Authority,
Los Angeles Department of Water and Power

SALT RIVER PROJECT

COMBINED FINANCIAL STATEMENTS
AS OF APRIL 30, 2015 AND 2014
TOGETHER WITH REPORT OF INDEPENDENT AUDITORS

SALT RIVER PROJECT

COMBINED BALANCE SHEETS
APRIL 30, 2015 AND 2014
(Thousands)

ASSETS

	2015	2014
Utility Plant		
Plant in service —		
Electric	$ 13,526,004	$ 12,859,145
Irrigation	370,852	366,464
Common	762,623	731,053
Total plant in service	14,659,479	13,956,662
Less — Accumulated depreciation on plant in service	(6,942,337)	(6,501,964)
	7,717,142	7,454,698
Plant held for future use	41,044	41,044
Construction work in progress	456,389	514,032
Nuclear fuel, net	131,222	127,195
	8,345,797	8,136,969
Other Property and Investments		
Non-utility property and other investments	279,799	290,899
Segregated funds, net of current portion	1,159,546	1,092,718
	1,439,345	1,383,617
Current Assets		
Cash and cash equivalents	123,226	264,103
Temporary investments	123,145	121,202
Current portion of segregated funds	98,956	99,070
Receivables, net of allowance for doubtful accounts	251,811	254,713
Fuel stocks	82,710	48,908
Materials and supplies	170,085	153,972
Current commodity derivative assets	19,610	14,315
Other current assets	18,904	20,295
	888,447	976,578
Deferred Charges and Other Assets		
Regulatory assets	991,511	945,298
Non-current commodity derivative assets	12,097	6,556
Other deferred charges and other assets	54,980	48,710
	1,058,588	1,000,564
Total Assets	$ 11,732,177	$ 11,497,728

The accompanying notes are an integral part of these combined financial statements.

SALT RIVER PROJECT
COMBINED BALANCE SHEETS
APRIL 30, 2015 AND 2014
(Thousands)

CAPITALIZATION AND LIABILITIES

	2015	2014
Long-term Debt and Capital Lease Obligation	$ 4,274,885	$ 4,413,028
Accumulated Net Revenues	4,694,745	4,735,895
Total Capitalization	8,969,630	9,148,923
Current Liabilities		
Current portion of long-term debt and capital lease obligation	122,253	110,196
Accounts payable	207,630	176,727
Accrued taxes and tax equivalents	122,436	116,315
Accrued interest	63,230	64,657
Customers' deposits	89,714	89,453
Current commodity derivative liabilities	64,062	8,140
Other current liabilities	241,185	231,578
	910,510	797,066
Deferred Credits and Other Non-current Liabilities		
Accrued post-retirement liability	1,029,658	941,442
Asset retirement obligations	268,413	152,886
Non-current commodity derivative liabilities	96,358	46,375
Other deferred credits and other non-current liabilities	457,608	411,036
	1,852,037	1,551,739
Commitments and Contingencies		
(Notes 7, 9, 11, 12, and 13)		
Total Capitalization and Liabilities	$ 11,732,177	$ 11,497,728

The accompanying notes are an integral part of these combined financial statements.

SALT RIVER PROJECT

COMBINED STATEMENTS OF NET REVENUES
FOR THE YEARS ENDED APRIL 30, 2015 AND 2014
(Thousands)

	2015	2014
Operating Revenues		
Retail electric	$ 2,658,739	$ 2,576,367
Other electric	65,746	67,535
Wholesale	292,822	311,655
Water	15,802	14,171
Total operating revenues	3,033,109	2,969,728
Operating Expenses		
Power purchased	376,506	374,549
Fuel used in electric generation	844,848	652,357
Other operating expenses	729,638	724,192
Maintenance	319,807	283,084
Depreciation and amortization	524,165	469,406
Taxes and tax equivalents	161,644	160,492
Total operating expenses	2,956,608	2,664,080
Net operating revenues	76,501	305,648
Other Income		
Investment income, net	47,616	75,515
Other income (deductions), net	19,365	21,226
Total other income, net	66,981	96,741
Net revenues before financing costs	143,482	402,389
Financing Costs		
Interest on bonds, net	174,000	178,379
Capitalized interest	(12,897)	(14,641)
Amortization of bond discount/premium and issuance expenses	(14,944)	(17,311)
Interest on other obligations	38,473	43,879
Net financing costs	184,632	190,306
Net Revenues	$ (41,150)	$ 212,083

The accompanying notes are an integral part of these combined financial statements.

SALT RIVER PROJECT

COMBINED STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED APRIL 30, 2015 AND 2014

(Thousands)

	2015	2014
Cash Flows from Operating Activities		
Net Revenues	$ (41,150)	$ 212,083
Adjustments to reconcile net revenues to net cash provided by operating activities:		
Depreciation and amortization	524,165	469,406
Amortization of nuclear fuel	45,513	44,424
Amortization of bond discount/premium and issuance expenses	(14,944)	(17,311)
Change in fair value of derivative instruments	95,069	(33,397)
Change in fair value of investment securities	(12,580)	(5,066)
Other	(1,855)	718
Decrease (increase) in:		
Fuel stocks and materials and supplies	(49,915)	27,968
Receivables, net of allowance for doubtful accounts	2,902	(18,171)
Other current assets	1,391	6,126
Deferred charges and other assets	(8,403)	(1,083)
Increase (decrease) in:		
Accounts payable	1,655	(18,724)
Accrued taxes and tax equivalents	6,121	65,434
Accrued interest	(1,427)	(5,081)
Customer deposits and other current liabilities	9,868	15,269
Deferred credits and other non-current liabilities	85,270	177,037
Net cash provided by operating activities	641,680	919,632
Cash Flows from Investing Activities		
Additions to utility plant, net	(643,570)	(530,551)
Proceeds from disposition of assets	3,789	4,261
Purchases of investments	(753,209)	(1,865,507)
Sales of investments	592,173	1,758,801
Maturities of investments	151,242	73,074
Net change in short-term investments related to segregated funds	(27,194)	(107,635)
Insurance proceeds	4,400	707
Net cash used for investing activities	(672,369)	(666,850)
Cash Flows from Financing Activities		
Proceeds from issuance of commercial paper	–	75,000
Capital lease principal payments	(14,143)	(13,103)
Repayment of long-term debt, including refundings	(96,045)	(288,300)
Net cash used for financing activities	(110,188)	(226,403)
Net Increase (Decrease) in Cash and Cash Equivalents	(140,877)	26,379
Balance at Beginning of Year in Cash and Cash Equivalents	264,103	237,724
Balance at End of Year in Cash and Cash Equivalents	$ 123,226	$ 264,103
Supplemental Information		
Cash paid for interest	$201,003	$212,698

The accompanying notes are an integral part of these combined financial statements.

[1] BASIS OF PRESENTATION:

THE COMPANY

The Salt River Project Agricultural Improvement and Power District (the District) is an agricultural improvement district organized in 1937 under the laws of the State of Arizona. It operates the Salt River Project (the Project), a federal reclamation project, under contracts with the Salt River Valley Water Users' Association (the Association), by which it has assumed the obligations and assets of the Association, including its obligations to the United States of America for the care, operation and maintenance of the Project. The District owns and operates an electric system that generates, purchases, transmits and distributes electric power and energy, and provides electric service to residential, commercial, industrial and agricultural power users in a 2,900 square mile service territory in parts of Maricopa, Gila and Pinal counties, plus mine loads in an adjacent 2,400 square mile area in Gila and Pinal counties. The Association, incorporated under the laws of the Territory of Arizona in 1903, operates an irrigation system as the agent of the District. The District and the Association are together referred to as SRP.

PRINCIPLES OF COMBINATION

The accompanying Combined Financial Statements reflect the combined accounts of the Association and the District. The District's financial statements are consolidated with its wholly owned taxable subsidiaries: SRP Captive Risk Solutions, Limited (CRS), Papago Park Center, Inc. (PPC) and New West Energy Corporation (New West Energy). CRS is a domestic captive insurer incorporated primarily to access property/boiler and machinery insurance coverage under the federal Terrorism Risk Insurance Act of 2002 for certified acts of terrorism. PPC is a real estate management company. New West Energy was used to market, at retail, energy available to the District that was surplus to the needs of its retail customers and energy that might have been rendered surplus in Arizona by retail competition in the supply of generation but is now largely inactive. All intercompany transactions and balances have been eliminated.

POSSESSION AND USE OF UTILITY PLANT

The United States of America retains a paramount right or claim in the Project that arises from the original construction and operation of certain of the Project's electric and water facilities as a federal reclamation project. Rights to the possession and use of, and to all revenues produced by, these facilities are evidenced by contractual arrangements with the United States of America.

BASIS OF ACCOUNTING

The accompanying Combined Financial Statements are presented in conformity with accounting principles generally accepted in the United States of America (U.S. GAAP). The preparation of financial statements in compliance with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts in the financial statements and disclosures of contingencies. Actual results could differ from the estimates.

By virtue of SRP operating a federal reclamation project under contract, with the federal government's paramount rights, asset ownership and certain approval rights, SRP is subject to accounting standards as set forth by the Federal Accounting Standards Advisory Board (FASAB). Entities reporting in accordance with the standards issued by the Financial Accounting Standards Board (FASB) prior to October 19, 1999 (the date the American

Institute of Certified Public Accountants (AICPA) designated the FASAB as the accounting standard-setting body for entities under the federal government), are permitted to continue to report in accordance with those standards. As permitted, SRP has elected to report its financial statements in accordance with FASB standards.

[2] SIGNIFICANT ACCOUNTING POLICIES:

UTILITY PLANT

Utility plant is stated at the historical cost of construction. Capitalized construction costs include labor, materials, services purchased under contract, and allocations of indirect charges for engineering, supervision, transportation, and administrative expenses and an allowance for funds used during construction (AFUDC). The cost of property that is replaced, removed or abandoned, less salvage, is charged to accumulated depreciation. Repairs and maintenance costs are charged to maintenance expense.

Depreciation expense is computed on a straight-line basis over recovery periods of the various classes of plant assets. Depreciation expense for utility plant totaled $496.6 million and $465.7 million for the years ended April 30, 2015 and 2014, respectively. In fiscal year 2014, depreciation expense reflects a reduction of $8.1 million which represents the correction of balances from prior periods. SRP determined that this amount is not material to the prior year's financial results. The following table reflects the District's average depreciation rates on the average cost of depreciable assets for the fiscal years ended April 30:

	2015	2014
Average electric depreciation rate	3.41%	3.30%
Average irrigation depreciation rate	1.63%	1.60%
Average common depreciation rate	5.33%	6.94%

For the years ended April 30, 2015 and 2014, there was $29.2 million and $9.1 million of non-cash investing activities related to property, plant and equipment purchases within accounts payable.

PLANT HELD FOR FUTURE USE

Plant held for future use primarily includes the cost of land acquired for future operations, including generation, transmission and other purposes. Once development starts on the new facility, the cost will be moved to construction work in progress.

ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION

AFUDC is the estimated cost of funds used to finance plant additions and is recovered in prices through depreciation expense over the useful life of the related asset. AFUDC is capitalized during certain plant construction and included in capitalized interest in the accompanying Combined Statements of Net Revenue. Composite rates of 4.25% and 4.31% were applied in fiscal years 2015 and 2014 to calculate interest on funds used to finance construction work in progress, resulting in $12.9 million and $14.6 million of interest capitalized, respectively.

NUCLEAR FUEL

SRP amortizes the cost of nuclear fuel using the units-of-production method. The units-of-production method is an amortization method based on actual physical usage. The nuclear fuel amortization and accrued expenses for both the interim and permanent disposal of spent nuclear fuel are components of fuel expense. Nuclear fuel amortization was $45.5 million and $44.4 million in fiscal years 2015 and 2014, respectively. Accumulated amortization of nuclear fuel at April 30, 2015 and 2014, was $684.1 million and $638.6 million, respectively. (See Note [13], CONTINGENCIES, Spent Nuclear Fuel, for additional information.)

ASSET RETIREMENT OBLIGATIONS

SRP accounts for its asset retirement obligations in accordance with authoritative guidance which requires the recognition and measurement of liabilities for legal obligations associated with the retirement of tangible long-lived assets. Liabilities for asset retirement obligations are recognized at fair value as incurred and capitalized as part of the cost of the related tangible long-lived assets. Accretion of the liabilities, due to the passage of time, is an operating expense and the capitalized cost is depreciated over the useful life of the long-lived asset. Retirement obligations associated with long-lived assets are those for which a legal obligation exists under enacted laws, statutes, and contracts, including obligations arising under the doctrine of promissory estoppel.

The District has identified retirement obligations for Palo Verde Nuclear Generating Station (PVNGS), Navajo Generating Station (NGS), Four Corners Generating Station (Four Corners), Mesquite Generating Station (Mesquite), and certain other assets. Additional retirement obligations were added in fiscal year 2015 for coal combustion residuals as further described below. Amounts recorded for asset retirement obligations are subject to various assumptions and determinations, such as determining whether an obligation exists to remove assets, estimating the fair value of the costs of removal, estimating when final removal will occur, and determining the credit-adjusted, risk-free interest rates to be utilized on discounting future liabilities. Subsequent to the initial recognition, the liability is adjusted for any revisions to the estimated future cash flows associated with the asset retirement obligation (with corresponding adjustments to utility plant), which can occur due to a number of factors, including, but not limited to, cost escalation, changes in technology applicable to the assets to be retired, changes in federal, state and local regulations, and changes to the estimated decommissioning date of the assets, as well as for accretion of the liability due to the passage of time until the obligation is settled. The PVNGS asset retirement obligation was increased by $20.5 million in fiscal year 2014 based on the receipt of an updated decommissioning cost study. The primary cause of the increase was an increase in the total estimated costs based on current regulatory requirements. The Mesquite asset retirement obligation was decreased in fiscal year 2014 by $6.8 million as a result of receiving updated cost study information.

As further described in Note (13), CONTINGENCIES, the Environmental Protection Agency (EPA) issued a final rule (the Rule) on December 19, 2014, that established federal criteria for management of coal combustion residuals (CCRs) as solid non-hazardous waste. As part of complying with the new Rule, SRP is required to formalize plans to close the various wet and dry ponds and landfills at its coal generating plants under the new guidelines set forth in the Rule. SRP is in the process of developing closure plans and acquiring cost studies to estimate the increased liability arising from these closure plans. The Rule allows for up to eighteen months from the effective date of the Rule for these plans to be completed. As of April 30, 2015, SRP has used available information to estimate an additional liability of $107.0 million to comply with the new requirements. As the closure plans are finalized and formal cost studies are obtained over the next two years, this estimate may change.

The following table summarizes the asset retirement obligation activity of the District at April 30 (in thousands):

	2015	2014
Beginning balance, May 1	$ 152,886	$ 131,764
Additions for Coal Combustion Residuals	107,000	–
Revisions	–	13,715
Accretion expense	8,527	7,407
Ending balance, April 30	$ 268,413	$ 152,886

INVESTMENTS IN DEBT AND EQUITY SECURITIES

SRP invests in various debt and equity securities. Debt securities that SRP has the positive intent and ability to hold to maturity are classified as held-to-maturity securities and reported at amortized cost. Debt and equity securities that are bought and held with the likelihood of selling them in the near term are classified as trading securities and reported at fair value, with unrealized gains and losses included in investment income, net. SRP has adopted the fair value option for all debt and equity securities other than those classified as held-to-maturity securities. All such securities are reported at fair value, with unrealized gains and losses included in investment income, net. SRP does not classify any securities as available-for-sale. (See Note [4], FAIR VALUE OF FINANCIAL INSTRUMENTS.)

SEGREGATED FUNDS

The District sets aside funds that are segregated due to management intent and to support various purposes. The District also has certain segregated funds that are legally restricted. The following amounts are included in segregated funds in the accompanying Combined Balance Sheets at April 30 (in thousands):

	2015	2014
Segregated funds — legally restricted		
Nuclear Decommissioning Trust	$ 350,719	$ 328,166
Debt Reserve Fund	80,598	80,598
Other	32,644	30,405
Total segregated funds — legally restricted	463,961	439,169
Segregated funds — other		
Benefits funds	695,585	653,351
Debt Service Fund	98,956	99,070
Other	–	198
Total segregated funds — other	794,541	752,619
Total segregated funds, including current portion	$ 1,258,502	$ 1,191,788

NUCLEAR DECOMMISSIONING

In accordance with regulations of the Nuclear Regulatory Commission (NRC), the District maintains a trust for the decommissioning of PVNGS. The Nuclear Decommissioning Trust (NDT) funds are invested in debt and equity securities. All NDT securities are reported as trading securities. SRP has elected the fair value option for such securities. Changes in fair value related to the NDT securities are included in the nuclear decommissioning regulatory asset or liability with no impact to net income. (See Note [3], REGULATORY MATTERS, for additional information about the nuclear decommissioning regulatory asset or liability.) The NDT funds, stated at fair value, as of April 30, 2015 and 2014, were $350.7 million and $328.2 million, respectively. The NDT funds are classified as segregated funds in the accompanying Combined Balance Sheets and are exempt from federal and state income taxes. (See Note [4], FAIR VALUE OF FINANCIAL INSTRUMENTS, for additional information about the NDT.)

CASH EQUIVALENTS

Cash equivalents include money market funds and highly liquid short-term investments with original maturities of three months or less, excluding negative account balances due to outstanding checks that are included in accounts payable, those short-term investments included as part of the segregated funds, and investments included in non-utility property and other investments in the accompanying Combined Balance Sheets. (For further discussion of financial instruments, see Note [6], FAIR VALUE MEASUREMENTS.)

ALLOWANCE FOR DOUBTFUL ACCOUNTS

Allowance for doubtful accounts is provided for electric customer accounts and other non-energy receivables balances based upon a historical experience rate of write-offs of accounts receivable as compared to retail electric revenues. The allowance account is adjusted periodically for this experience rate and is maintained until either receipt of payment or the likelihood of collection is considered remote, at which time the allowance account and corresponding receivable balance are written off. SRP has provided for an allowance for doubtful accounts of $2.0 million and $1.7 million as of April 30, 2015 and 2014, respectively.

FUEL STOCKS AND MATERIALS AND SUPPLIES

Fuel stocks and materials and supplies are stated at weighted average cost, and are valued using the average cost method.

OTHER CURRENT LIABILITIES

The accompanying Combined Balance Sheets include the following other current liabilities as of April 30 (in thousands):

	2015	2014
Sick, vacation and holiday (SVHL) accrual	$ 87,848	$ 87,559
Budget billing plan	66,327	64,791
Employee Performance Incentive Compensation (EPIC)	22,895	22,604
Post-retirement benefits	26,024	26,152
Other	38,091	30,472
Total other current liabilities	$ 241,185	$ 231,578

(See Note [9], EMPLOYEE BENEFIT PLANS AND INCENTIVE PROGRAMS, for additional information on the benefit-related other current liabilities.)

OTHER INCOME (DEDUCTIONS), NET

Other income (deductions), net, includes non-operating income and expense items, such as the effects of various settlements and refunds.

FINANCING COSTS

Bond discount, premium and issuance expenses are deferred and amortized using the effective interest method over the terms of the related bond issues.

INCOME TAXES

The District, as a political subdivision of the State of Arizona, is exempt from federal and Arizona state income taxes. The Association, as a private corporation, is not exempt from federal and Arizona state income taxes. However, the Association is not liable for income taxes on operations relating to its acting as an agent for the District on the basis of a settlement with the Commissioner of Internal Revenue in 1949, which was approved by the Secretary of the Treasury. The Association is liable for income taxes on activities where it is not acting as an agent of the District. Income taxes related to the District's wholly owned taxable subsidiaries' operations are not material to the accompanying Combined Financial Statements.

VOLUNTARY CONTRIBUTIONS IN LIEU OF TAXES

As a political subdivision of the State of Arizona, the District is exempt from property taxation. In accordance with Arizona law, the District makes voluntary contributions each year to the State of Arizona, school districts, cities, counties, towns and other political subdivisions of the State of Arizona, for which property taxes are levied and within whose boundaries the District has property included in its electric system. The amount paid is computed on the same basis as ad valorem taxes paid by a private utility corporation with an allowance for certain water-related deductions. Contributions based on the costs of construction work in progress are capitalized, and those based on plant-in-service are expensed.

SALES AND USE TAXES

The District is required by various government authorities, including states and municipalities, to collect and remit taxes on certain retail sales. Such taxes are recorded on a net basis and excluded from revenues and expenses in the accompanying Combined Financial Statements.

REVENUE RECOGNITION

SRP recognizes electric revenues when billed and accrues estimated revenue for electricity delivered to customers that has not yet been billed. The estimated revenue for electricity delivered but not yet billed is included in retail electric revenue and in receivables, net, and was $75.2 million and $73.3 million at April 30, 2015 and 2014, respectively. Some customers pay in advance under level payment billing plans. Such advance payments are deferred and included in other current liabilities in the combined balance sheets. In addition to the retail electric revenues, SRP generates revenues from wholesale, transmission, telecommunications and water activities.

Wholesale revenues include wholesale excess energy sales. Wholesale revenues are recognized when earned. Transmission revenues are earned by allowing other entities to use SRP's transmission facilities to transmit power. The transmission revenues are recognized as earned and are included in other electric revenues on the combined statement of net revenues. SRP earns telecommunications revenue by allowing companies to use SRP's infrastructure to place antennas that are used to transmit communications signals. Telecommunication revenues are recognized when earned and are included in other electric revenues on the combined statement of net revenues. SRP earns water revenues from providing water to SRP water customers through annual assessments, supplemental water assessments and various other fees and charges. Water revenues are recognized when earned and are included in water revenues on the combined statement of net revenues.

The electric industry engages in an activity called "book-out", under which some energy purchases are netted against sales and power does not actually flow in settlement of the contract. SRP presents the impacts of these financially settled contracts on a net basis, which resulted in a net reduction to revenue and purchased power expense of $58.1 million and $56.9 million for fiscal years 2015 and 2014, respectively, but which did not affect net revenues or cash flows.

CONCENTRATIONS OF CREDIT RISK

Financial instruments that potentially subject SRP to credit risk consist of cash and cash equivalents, temporary and other investments, and segregated funds. Certain balances exceed Federal Deposit Insurance Corporation (FDIC) insured limits or are invested in money market accounts with investment banks that are not FDIC insured. SRP's cash and cash equivalents, temporary and other investments, and segregated funds are placed in creditworthy financial institutions, and certain money market accounts that invest in U.S. Treasury Securities or other obligations issued or guaranteed by the U.S. government or its agencies or instrumentalities.

The use of contractual arrangements to manage the risks associated with changes in energy commodity prices creates credit risks resulting from the possibility of nonperformance by counterparties pursuant to the terms of their contractual obligations. In addition, volatile energy prices can create significant credit exposure from energy market receivables and mark-to-market valuations. The District has a credit policy for wholesale counterparties, continuously monitors credit exposures, and routinely assesses the financial strength of its counterparties. The District minimizes credit risk by dealing primarily with creditworthy counterparties, entering into standardized agreements that allow netting of exposures to and from a single counterparty, and requiring letters of credit, parent guarantees or other collateral when it does not consider the financial strength of the counterparty sufficient.

RECENTLY ISSUED ACCOUNTING STANDARDS

On April 7, 2015, the FASB issued Accounting Standards Update (ASU) 2015-03, *Simplifying the Presentation of Debt Issuance Costs*, which requires debt issuance costs to be presented in the balance sheet as a direct deduction from the carrying value of the associated debt liability, consistent with the presentation of a debt discount. The standard is effective for SRP for financial statements issued for fiscal years beginning after December 15, 2015. SRP has not elected to early-adopt this new standard.

On May 1, 2015, the FASB issued Accounting Standards Update (ASU) 2015-07, *Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent)*. For entities that measure an investment's fair value using the net asset value per share (or an equivalent) practical expedient, the amendments in ASU No. 2015-07 eliminate the requirement to classify the investment within the fair value hierarchy. In addition, the requirement to make specific disclosures for all investments eligible to be assessed at fair value with the net asset value per share practical expedient has been removed. Instead, such disclosures are restricted only to investments that the entity has decided to measure using the practical expedient. For SRP, the amendments will be effective for fiscal years starting after December 15, 2016. SRP is currently evaluating the impact this may have, if any, on its financial statements.

In 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers*. The new standard replaces the previous revenue recognition guidance contained in Topic 605. SRP is required to apply the revenue standard for the fiscal year beginning May 1, 2019. SRP is currently evaluating what impact the new standard may have on its financial statements.

REVISION

In 2015, SRP identified an error in its historical accounting for depreciation expense that resulted in excess accumulated depreciation of approximately $73.8 million as of April 30, 2014. The excess accumulated depreciation was the result of excess depreciation expense recorded over an approximate 15-year period that should have been recorded as a regulatory liability. SRP determined that the adjustment to correct the error was not material to any previously issued prior period financial results, but the cumulative adjustment to correct the error in the current period would have been material to fiscal year 2015 operating revenues and operating expenses. Accordingly, SRP revised its April 30, 2014, Combined Balance Sheet, Combined Statement of Net Revenues and Combined Statement of Cash Flows to correct for the errors and appropriately reflect depreciation expense. This revision resulted in no change in beginning of the fiscal year 2015 or 2014 accumulated net revenues. On the 2014 Statement of Combined Net Revenues, depreciation and amortization expense was reduced by $11.1 million and retail electric revenues were reduced by the same amount, resulting in no change to net revenues for the year ended April 30, 2014. Accumulated Depreciation on Plant in Service decreased by $73.8 million and Other Deferred Credits and Other Non-current Liabilities increased by $73.8 million on the Combined Balance Sheet as of April 30, 2014. There was no effect on any of the subtotals or totals on the Combined Statement of Cash Flows for the year ended April 30, 2014.

SUBSEQUENT EVENTS

SRP follows authoritative guidance which requires an entity to evaluate subsequent events through the date that the financial statements are either issued or available to be issued. Subsequent events for SRP have been evaluated through July 17, 2015, which is the date that the financial statements were issued. (See Note [7], LONG-TERM DEBT AND CAPITAL LEASE OBLIGATION, Note [8], COMMERCIAL PAPER AND CREDIT AGREEMENTS, and Note [14], SUBSEQUENT EVENTS, for further description of events occurring subsequent to April 30, 2015.)

[3] REGULATORY MATTERS:

THE ELECTRIC UTILITY INDUSTRY

The District operates in a highly regulated environment in which it has an obligation to deliver electric service to customers within its service area. In 1998, Arizona enacted the Arizona Electric Power Competition Act (the Act), which authorized competition in the retail sales of electric generation, recovery of stranded costs, and competition in billing, metering and meter reading. While retail competition was available to all customers by 2001, only a few customers chose an alternative energy provider and those customers have since returned to their incumbent utilities. At this time, there is no active retail competition within the District's service territory or, to the knowledge of the District, within the State of Arizona, and the District's Direct Access Program is suspended.

Since 2006, various energy service, meter reading and meter service providers, as well as brokers, have applied to the Arizona Corporation Commission (ACC) for authorization to sell competitive services in Arizona, but the ACC has not ruled on any of the applications. However, effective July 1, 2012, the ACC approved another major Arizona utility's proposed buy-through pilot program whereby a limited number of large industrial customers are now allowed to purchase generation from other providers. In addition, energy service providers, large industrial customers and merchant power plant owners have been urging the ACC to reinstate some form of retail competition.

At the request of the ACC and after a lengthy public process, the ACC staff issued a report in August 2010 recommending that, should the ACC choose to revisit competition, it should do so cautiously and determine if it is in the public interest.

In May 2013, in response to various applications received, the ACC opened a further inquiry into retail competition, requesting that interested parties provide comments on a series of ACC-issued questions. The District participated in this inquiry. On September 11, 2013, the ACC voted to close its docket regarding whether it should consider deregulation of the Arizona electricity market. The ACC's action is consistent with SRP's position in its filing with the ACC on this docket.

REGULATION AND PRICING POLICIES

Under Arizona law, the District's publicly elected Board of Directors (the Board) has the authority to establish electric prices. The District is required to follow certain public notice and special Board meeting procedures before implementing any changes in the standard electric price plans. The financial statements reflect the pricing policies of the District's Board.

The District's price plans include a base price component, a Fuel and Purchased Power Adjustment Mechanism (FPPAM) and an Environmental Programs Cost Adjustment Factor (EPCAF). Base prices recover costs for generation, transmission, distribution, customer services, metering, meter reading, billing and collections, and system benefits charges that are not otherwise recovered through the FPPAM or EPCAF. The FPPAM was implemented in May 2002 to adjust for increases and decreases in fuel costs. The EPCAF was implemented in November 2009 to cover costs incurred by the District to comply with requirements imposed by mandate that are related to renewable-energy, energy efficiency and climate change. Through a system benefits surcharge to the District's transmission and distribution customers, the District recovers the costs of programs benefiting the general public, such as discounted rates for low-income customers and nuclear decommissioning, including the cost of spent fuel storage.

On February 26, 2015, the Board concluded a public process by approving changes and adjustments to its price plans, including an overall average annual price increase of 3.9 percent, to be phased in beginning with the April 2015 billing cycle, which for most customers begins sometime in March. This overall increase was comprised of a 4.4 percent base increase and a 0.5 percent EPCAF decrease. There was no material change to the FPPAM. In addition to other approved changes and adjustments, the Board approved a new price plan for residential customers who, after December 8, 2014, add solar or other technologies to generate some of their energy requirements. See Note (13), CONTINGENCIES, for further information regarding the price process.

REGULATORY ACCOUNTING

SRP accounts for the financial effects of the regulated portion of its operations in accordance with the provisions of authoritative guidance for regulated enterprises, which requires cost-based, rate-regulated utilities to reflect the impacts of regulatory decisions in their financial statements. SRP records regulatory assets, which represent probable future recovery of certain costs from customers through the pricing process, and regulatory liabilities, which represent probable future credits to customers through the ratemaking process. Based on actions of the Board, SRP believes the future collection of costs deferred as regulatory assets is probable. If events were to occur making recovery of these regulatory assets no longer probable, SRP would be required to write off the remaining balance of such assets as a one-time charge to net revenues. None of the regulatory assets earn a rate of return.

The accompanying Combined Balance Sheets include the following regulatory assets and liabilities as of April 30 (in thousands):

Assets	2015	2014
Pension and other post-retirement benefits (Note [9])	$ 902,638	$ 844,134
Bond defeasance	82,494	88,163
Mohave Generating Station	5,200	13,001
Other	1,179	–
Total regulatory assets	$ 991,511	$ 945,298
Liabilities		
Nuclear decommissioning	$ 170,498	$ 133,974
Depreciation	80,700	73,800
Total regulatory liabilities	$ 251,198	$ 207,774

The pension and other post-retirement benefits regulatory asset is adjusted as changes in actuarial gains and losses, prior service costs, and transition assets or obligations are recognized as components of net periodic pension costs each year and is recovered through prices charged to customers.

Bond defeasance regulatory assets are recovered over the remaining original amortization periods of the reacquired debt ending in various years through fiscal year 2032.

The Mohave Generating Station regulatory asset is being recovered on a straight-line basis over a ten-year period ending in fiscal year 2016.

The nuclear decommissioning regulatory liability is being deferred over the life of PVNGS and is being recovered through a component of the system benefits charge. Any difference between current year costs, revenues associated with nuclear decommissioning, and earnings (losses) on the NDT is deferred in accordance with authoritative guidance for regulated enterprises and has no impact to SRP's earnings.

The depreciation regulatory liability is being deferred over the estimated remaining lives of various classes of assets.

[4] FAIR VALUE OF FINANCIAL INSTRUMENTS:

SRP invests in U.S. government obligations, certificates of deposit and other marketable investments. Such investments are classified as cash and cash equivalents, temporary investments, other investments, and segregated funds in the accompanying Combined Balance Sheets depending on the purpose and duration of the investment.

FAIR VALUE OPTION

SRP adopted authoritative guidance which permits an entity to choose to measure many financial instruments and certain other items at fair value. SRP has elected the fair value option for all investment securities other than those classified as held-to-maturity. Election of the fair value option requires the security to be reported as a trading security.

The fair value option was elected because management believes that fair value best represents the nature of the investments. While the investment securities held in these funds are reported as trading securities, the investments continue to be managed with a long-term focus. Accordingly, all purchases and sales within these funds are presented separately in the accompanying Combined Statements of Cash Flows as investing cash flows, consistent with the nature and purpose for which the securities are acquired.

Realized and unrealized gains and losses on these investments are included in investment income, net in the accompanying Combined Statements of Net Revenues.

The following table summarizes line items included in the accompanying Combined Balance Sheets at April 30 that include amounts recorded at fair value pursuant to the fair value option:

(in thousands)	Measurement Attribute*	2015	2014
Cash and cash equivalents			
Cash	N/A	$ 3,295	$ 10,952
Money market funds	Fair value	119,931	253,151
Total cash and cash equivalents		123,226	264,103
Non-utility property and other investments			
Money market funds	Fair value	2,119	2,326
Trading investments	Fair value	39,185	37,527
Held-to-maturity investments	Amortized cost	132,790	154,575
Non-utility property	N/A	105,705	96,471
Total non-utility property and other investments		279,799	290,899
Segregated funds, net of current portion			
Cash	N/A	–	197
Money market funds	Fair value	12,224	16,095
Trading investments	Fair value	1,072,501	1,007,379
Held-to-maturity investments	Amortized cost	74,821	69,047
Total segregated funds, net of current portion		1,159,546	1,092,718
Temporary investments			
Held-to-maturity investments	Amortized cost	123,145	121,202
Total temporary investments		123,145	121,202
Current portion of segregated funds			
Money market funds	Fair value	98,956	99,070
Total current portion of segregated funds		$ 98,956	$ 99,070

**N/A — Asset category not eligible for fair value option.*

SRP's investments in debt securities are measured and reported at amortized cost when there is positive intent and ability to hold the security to maturity. SRP's amortized cost and fair value of held-to-maturity securities were $330.8 million and $331.2 million, respectively, at April 30, 2015, and $344.8 million and $344.6 million, respectively, at April 30, 2014. At April 30, 2015, SRP's investments in debt securities have maturity dates ranging from June 2015 to December 2027.

SRP evaluates the held-to-maturity securities for other-than-temporary impairment on a periodic basis considering numerous factors. At April 30, 2015 and 2014, SRP did not hold any other-than-temporary impaired securities. As of April 30, 2015, the total unrecognized loss on held-to-maturity securities with amortized costs exceeding fair market value was approximately $0.5 million.

SRP's trading investments are measured at fair value with unrealized trading gains and losses included in investment income, net. Unrealized trading gains and losses on Nuclear Decommissioning Trust investments are included in nuclear decommissioning regulatory liability.

The following table summarizes unrealized gains (losses) from fair value changes related to investments still held at April 30 (in thousands):

	2015	2014
Segregated funds, net of current portion	$ 11,391	$ 2,895
Non-utility property and other investments	1,189	2,171
Investment income, net	$ 12,580	$ 5,066

[5] DERIVATIVE INSTRUMENTS:

ENERGY RISK MANAGEMENT ACTIVITIES

The District has an energy risk management program to limit exposure to risks inherent in normal energy business operations. The goal of the energy risk management program is to measure and manage exposure to market risks, credit risks and operational risks. Specific goals of the energy risk management program include reducing the impact of market fluctuations on energy commodity prices associated with customer energy requirements, excess generation and fuel expenses, in addition to meeting customer pricing needs, and maximizing the value of physical generating assets. The District employs established policies and procedures to meet the goals of the energy risk management program using various physical and financial instruments, including forward contracts, futures, swaps and options.

Certain of these transactions are accounted for as commodity derivatives and are recorded in the accompanying Combined Balance Sheets as either an asset or liability measured at their fair value. Derivative instruments and the related collateral accounts, if applicable, that are subject to master netting agreements are presented as a net asset or liability on the Combined Balance Sheets. Changes in the fair value of commodity derivatives are recognized each period in current earnings and included in the accompanying Combined Statements of Net Revenues and classified as part of operating cash flows in the accompanying Combined Statements of Cash Flows. Some of the District's contractual agreements qualify and are designated for the normal purchases and normal sales exception and are not recorded at market value. This exception applies to physical sales and purchases of power or fuel where it is probable that physical delivery will occur; the pricing provisions are clearly and closely related to the underlying asset; and the documentation requirements are met. If a contract qualifies for the normal purchases and normal sales scope exception, the District accounts for the contract using settlement accounting (costs and revenues are recorded when physical delivery occurs). SRP has not elected to use hedge accounting for its derivative investments.

See Note (6), FAIR VALUE MEASUREMENTS, for additional information on derivative valuation.

DERIVATIVE VOLUMES

The District has the following gross derivative volumes, by type, at April 30, 2015:

Commodity	Unit of Measure	Sales Volumes	Purchases Volumes
Natural gas options, swaps and forward arrangements	MMBtu	57,695,000	136,362,500
Electricity options, swaps and forward arrangements	MWh	5,000,350	1,873,260
Liquefied fuel swaps	Gallon	–	3,549,600

The District has the following gross derivative volumes, by type, at April 30, 2014:

Commodity	Unit of Measure	Sales Volumes	Purchases Volumes
Natural gas options, swaps and forward arrangements	MMBtu	56,372,000	136,527,500
Electricity options, swaps and forward arrangements	MWh	2,371,625	2,173,689
Liquefied fuel swaps	Gallon	–	4,044,400

PRESENTATION OF DERIVATIVE INSTRUMENTS IN THE FINANCIAL STATEMENTS

The following tables provide information about the gross fair values, netting, and collateral and margin deposits for derivatives hedging instruments in the accompanying Combined Balance Sheets (in thousands):

APRIL 30, 2015	Current Commodity Derivative Assets	Non-current Commodity Derivative Assets	Current Commodity Derivative Liabilities	Non-current Commodity Derivative Liabilities	Total Assets (Liabilities)
Commodities	$ 12,478	$ 22,404	$ (70,075)	$ (106,665)	$ (141,858)
Netting	(6,013)	(10,307)	6,013	10,307	–
Collateral and margin deposits	13,145	–	–	–	13,145
Total	$ 19,610	$ 12,097	$ (64,062)	$ (96,358)	$ (128,713)

APRIL 30, 2014	Current Commodity Derivative Assets	Non-current Commodity Derivative Assets	Current Commodity Derivative Liabilities	Non-current Commodity Derivative Liabilities	Total Assets (Liabilities)
Commodities	$ 20,000	$ 15,291	$ (17,638)	$ (55,110)	$ (37,457)
Netting	(9,498)	(8,735)	9,498	8,735	–
Collateral and margin deposits	3,813	–	–	–	3,813
Total	$ 14,315	$ 6,556	$ (8,140)	$ (46,375)	$ (33,644)

The following tables summarize the District's unrealized gains (losses) associated with derivatives not designated as hedging instruments in the accompanying Combined Statements of Net Revenues (in thousands):

APRIL 30, 2015

	Operating Revenues	Power Purchased	Fuel Used in Electric Generation	Net Unrealized Gain (Loss)
Commodities	$ 17,301	$ (192)	$ (117,827)	$ (100,718)

APRIL 30, 2014

	Operating Revenues	Power Purchased	Fuel Used in Electric Generation	Net Unrealized Gain (Loss)
Commodities	$ 11,967	$ (69)	$ 41,811	$ 53,709

CREDIT RELATED CONTINGENT FEATURES

Certain of the District's derivative instruments contain provisions that require the District to post additional collateral upon certain credit events. If the District's debt were to fall below investment grade, the counterparties to the derivative instruments could demand immediate and ongoing full overnight collateralization on derivative instruments in net liability positions.

The aggregate fair value of all derivative liabilities with credit-risk-related contingent features as of April 30, 2015, was $149.9 million, for which the District is not required to post collateral. If the credit-risk-related contingent features underlying these agreements were triggered on April 30, 2015, the District could be required to post up to $149.9 million of collateral to its counterparties.

[6] FAIR VALUE MEASUREMENTS:

SRP accounts for fair value in accordance with authoritative guidance, which defines fair value, establishes methods for measuring fair value by applying one of three observable market techniques (market approach, income approach or cost approach) and establishes required disclosures about fair value measurements. This standard defines fair value as the price that would be received for an asset, or paid to transfer a liability, in the most advantageous market for the asset or liability in an arms-length transaction between willing market participants at the measurement date. SRP determines fair value of its financial instruments based on the market approach, which is defined as a valuation technique that uses prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities.

SRP has categorized its financial instruments, based on the priority of the inputs to the valuation technique, into a three-level fair value hierarchy. The fair value hierarchy gives the highest priority to quoted prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). The three levels of the fair value hierarchy are as follows:

Level 1: Financial assets and liabilities whose values are based on unadjusted quoted prices for identical assets or liabilities in an active market.

Level 2: Financial assets and liabilities whose values are based on quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in non-active markets, pricing models whose inputs are observable for substantially the full term of the asset or liabilities and pricing models whose inputs are derived principally from or corroborated by observable market data through correlation or other means.

Level 3: Financial assets and liabilities whose values are based on prices or valuation techniques that require inputs that are both unobservable and significant to the overall fair value measurement. These inputs reflect management's own assumptions about the assumptions a market participant would use in pricing the asset or liability.

The following table sets forth, by level within the fair value hierarchy, SRP's financial assets and liabilities that were accounted for at fair value on a recurring basis as of April 30, 2015 (in thousands):

	Level 1	Level 2	Level 3	Netting and Collateral	Total
ASSETS					
Cash and cash equivalents:					
Money market funds	$ –	$ 119,931	$ –	$ –	$ 119,931
Total cash and cash equivalents	–	119,931	–	–	119,931
Non-utility property and other investments:					
Money market funds	–	2,119	–	–	2,119
Mutual funds	39,185	–	–	–	39,185
Total non-utility property and other investments	39,185	2,119	–	–	41,304
Segregated funds, net of current portion:					
Money market funds	–	12,224	–	–	12,224
Mutual funds	530,279	–	–	–	530,279
Commingled funds	–	191,509	14	–	191,523
Common stocks	319,769	–	–	–	319,769
Corporate bonds	–	14,302	–	–	14,302
U.S. government securities	–	16,628	–	–	16,628
Total segregated funds, net of current portion	850,048	234,663	14	–	1,084,725
Current portion of segregated funds:					
Money market funds	–	98,956	–	–	98,956
Total current portion of segregated funds	–	98,956	–	–	98,956
Derivative instruments:					
Commodities	12,451	21,940	491	(3,175)	31,707
Total	$ 901,684	$ 477,609	$ 505	$ (3,175)	$ 1,376,623
Liabilities					
Derivative instruments:					
Commodities	$ (12,137)	$ (135,922)	$ (28,681)	$ 16,320	$ (160,420)
Total	$ (12,137)	$ (135,922)	$ (28,681)	$ 16,320	$ (160,420)

The following table sets forth, by level within the fair value hierarchy, SRP's financial assets and liabilities that were accounted for at fair value on a recurring basis as of April 30, 2014 (in thousands):

	Level 1	Level 2	Level 3	Netting and Collateral	Total
ASSETS					
Cash and cash equivalents:					
Money market funds	$ –	$ 253,151	$ –	$ –	$ 253,151
Total cash and cash equivalents	–	253,151	–	–	253,151
Non-utility property and other investments:					
Money market funds	–	2,326	–	–	2,326
Mutual funds	37,527	–	–	–	37,527
Total non-utility property and other investments	37,527	2,326	–	–	39,853
Segregated funds, net of current portion:					
Money market funds	–	16,095	–	–	16,095
Mutual funds	506,810	–	–	–	506,810
Commingled funds	–	181,329	217	–	181,546
Common stocks	291,720	–	–	–	291,720
Corporate bonds	–	13,213	–	–	13,213
U.S. government securities	–	14,090	–	–	14,090
Total segregated funds, net of current portion	798,530	224,727	217	–	1,023,474
Current portion of segregated funds:					
Money market funds	–	99,070	–	–	99,070
Total current portion of segregated funds	–	99,070	–	–	99,070
Derivative instruments:					
Commodities	7,865	22,687	4,739	(14,420)	20,871
Total	$ 843,922	$ 601,961	$ 4,956	$ (14,420)	$ 1,436,419
Liabilities					
Derivative instruments:					
Commodities	$ (2,550)	$ (62,220)	$ (7,978)	$ 18,233	$ (54,515)
Total	$ (2,550)	$ (62,220)	$ (7,978)	$ 18,233	$ (54,515)

VALUATION METHODOLOGIES

Securities

Money market funds: Investments with maturities of three months or less when purchased, including certain short-term fixed-income securities, are considered cash equivalents. The fair value of shares in money market funds are priced based on inputs obtained from Bloomberg, a pricing service whose prices are obtained from direct feeds from exchanges, that are either directly or indirectly observable. Even though the NAV of the fund(s) is kept at $1 per share, and transactions occur at that price, the underlying value of the securities may or may not be equal to $1 per share; therefore, these funds are classified as Level 2 in the fair value hierarchy.

Mutual funds: The fair values of shares in mutual funds are based on inputs that are quoted prices in active markets for identical assets and, therefore, have been categorized in Level 1 in the fair value hierarchy. Mutual funds are priced using active market exchanges, and sources include Interactive Data Corporation (IDC), Bloomberg, Yahoo! Finance and other publicly available venues. This category may include Exchange-Traded Funds (ETFs), which are similar to mutual funds in their structure, but trade actively on exchanges like stocks. Pricing sources for ETFs also include IDC, Bloomberg, Yahoo! Finance and other publicly available venues.

Corporate stocks: The fair values of shares in preferred and common corporate stocks are based on inputs that are quoted prices in active markets for identical assets and, therefore, have been categorized in Level 1 in the fair value hierarchy. Equities are priced using active market exchanges. Preferred and common corporate stocks are valued based on quoted prices in active markets and are categorized in Level 1. Equity securities held individually are primarily traded on exchanges that contain only actively traded securities due to the volume trading requirements imposed by these exchanges. Common stocks that are valued based on quoted prices from less active markets, such as over-the-counter (OTC) stocks, are categorized as Level 2 in the fair value hierarchy. Pricing sources include Interactive Data Corporation (IDC), Bloomberg, Yahoo! Finance, or other publicly available venues.

U.S. government securities: The fair value of U.S. government securities is derived from quoted prices on similar assets in active or non-active markets, from pricing models whose inputs are observable for the substantially full term of the asset, or from pricing models whose inputs are derived principally from or corroborated by observable market data through correlation or other means; therefore, these securities have been categorized as Level 2 in the fair value hierarchy.

Commingled funds: Commingled funds are maintained by investment companies and hold certain investments in accordance with a stated set of fund objectives, which are consistent with SRP's overall investment strategy. For equity and fixed-income commingled funds, the fund administrator values the fund using the net asset value (NAV) per fund share, derived from the quoted prices in active markets of the underlying securities. Where adjustments to the NAV are required with respect to interests in funds subject to restrictions on redemption (such as lock-up periods or withdrawal limitations) and/or observable activity for the fund investment is limited, investments are classified within Levels 2 or 3 of the valuation hierarchy. If the ability to redeem the investment is unknown or the investment cannot be redeemed in the near term at NAV, the fair value measurement of the investment will be categorized as a Level 3 in the valuation hierarchy.

Corporate bonds: For fixed-income securities, multiple prices and price types are obtained from pricing vendors whenever possible, which enables cross-provider validations in addition to checks for unusual daily movements. A primary price source is identified based on asset type, class or issue for each security. SRP has obtained an understanding of how these prices are derived, including the nature and observability of the inputs used in deriving such prices. Additionally, SRP selectively corroborates the fair values of securities by comparison to other market-based price sources. The fair values of fixed-income securities are based on evaluated prices that reflect observable market information, such as actual trade information of similar securities, adjusted for observable differences and are categorized as Level 2.

Commodity Derivative Instruments

The fair values of gas swaps and power swaps that are priced based on inputs using quoted prices of similar exchange traded items have been categorized in Level 1 in the fair value hierarchy. These include gas and power swaps traded on exchanges.

The fair values of gas swaps, power swaps, gas options, power options and power deals that are priced based on inputs obtained through pricing agencies and developed pricing models, using similar observable items in active and inactive markets, are classified as Level 2 in the valuation hierarchy.

The fair values of derivatives assets and liabilities that are valued using pricing models with significant unobservable market data traded in less active or underdeveloped markets are classified as Level 3 in the valuation hierarchy. Level 3 items include gas swaps, power swaps, gas options, power options and power deals. These inputs reflect management's own assumptions about the assumptions a market participant would use in pricing the asset or liability (examples include long-dated or complex derivatives).

SRP does periodically transact at locations, market price points, or in time blocks that are non-standard or illiquid for which no prices are available from an independent pricing source. In these cases, we apply adjustments based on historical price curve relationships to a more liquid price point as a proxy for market prices. Such transactions are classified as Level 3.

SRP estimates the fair value of its options using Black-Scholes option pricing models which includes inputs such as implied volatility, correlations, interest rates, and forward price curves.

All of the assumptions above include adjustments for counterparty credit risk, using credit default swap data, bond yields, when available, or external credit ratings.

SRP's assessments of the significance of a particular input to the fair value measurements requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. SRP reviews the assumptions underlying its contracts monthly.

The following table provides quantitative information regarding significant unobservable inputs in SRP's Level 3 fair value measurements as of April 30, 2015:

FAIR VALUE AT APRIL 30, 2015
(in thousands)

	Assets	Liabilities	Range of Unobservable Inputs
Forward contracts:	$ 431	$ –	
Market price per MWh			$20.550–$47.300
Market price per MMBtu			$2.277–$3.779
Option contracts:	$ 60	$ (28,681)	
Market price per MWh			$26.900–$36.600
Market price per MMBtu			$2.277–$3.700
Power Volatility			18.00%–40.06%
Gas Volatility			24.40%–41.50%

The following table provides quantitative information regarding significant unobservable inputs in SRP's Level 3 fair value measurements as of April 30, 2014:

FAIR VALUE AT APRIL 30, 2014
(in thousands)

	Assets		Liabilities	Range of Unobservable Inputs
Forward contracts:	$	1,469	$ (682)	
Market price per MWh				$32.00–$55.20
Market price per MMBtu				$4.399–$4.998
Option contracts:	$	3,267	$ (7,296)	
Market price per MWh				$43.30–$45.85
Market price per MMBtu				$4.107–$4.863
Power Volatility				28.34%–31.83%
Gas Volatility				17.10%–31.70%

(See Note [5], DERIVATIVE INSTRUMENTS, for additional detail of derivatives.)

INVESTMENTS CALCULATED AT NET ASSET VALUE

As of April 30, 2015, the fair value measurement of investments calculated at net asset value per share (or its equivalent), as well as the nature and risks of those instruments, is as follows:

	Fair Value *(in thousands)*	Unfunded Commitments	Redemption Frequency	Redemption Notice Period
Mutual funds	$ 569,464	None	Daily	N/A
Commingled funds:				
Fixed income funds	191,509	None	Daily	N/A
Domestic long-short equity fund of funds	14	None	Annual	100 days

As of April 30, 2014, the fair value measurement of investments calculated at net asset value per share (or its equivalent), as well as the nature and risks of those instruments, is as follows:

	Fair Value *(in thousands)*	Unfunded Commitments	Redemption Frequency	Redemption Notice Period
Mutual funds	$ 544,337	None	Daily	N/A
Commingled funds:				
Fixed income funds	181,329	None	Daily	N/A
Domestic long-short equity fund of funds	217	None	Annual	100 days

Mutual funds: These are funds invested in either equity or fixed-income securities. They are actively managed funds that seek to outperform their respective benchmarks. The equity funds may invest in large and/or small capitalization stocks and/or growth or value styles, as dictated by their prospectuses. The fixed-income funds will invest in a broad array of securities, including treasuries, agencies, corporate debt, mortgage-backed securities, and some non-U.S. debt.

Fixed-income commingled funds: These funds are actively managed funds used by an investment manager to diversify an overall portfolio of separately managed fixed-income securities. The funds may invest in fixed-income securities of varying duration, maturity, credit quality and geographic location. The securities may be non-U.S. securities.

Domestic long-short equity fund of funds: The fund is an actively managed fund of funds that primarily invests in managers that invest in domestic and some non-U.S. equities. As a long-short fund, the fund seeks to neutralize market risk by balancing between managers that buy (go long) securities and managers who sell (go short) securities. The fund seeks to outperform a broad equity index over long periods, with less risk.

COLLATERAL AND MARGIN DEPOSITS

Margin and collateral deposits include cash deposited with counterparties and brokers as credit support under energy contracts. The amount of margin and collateral deposits generally varies based on changes in the fair value of the positions. SRP presents its margin and cash collateral deposits net with its derivative position on the accompanying Combined Balance Sheets. Amounts recognized as margin and collateral provided to others are included in derivative assets and/or derivative liabilities in the accompanying Combined Balance Sheets. The margin deposits included in derivative assets totaled $13.1 million and $3.8 million at April 30, 2015 and 2014, respectively.

CHANGES IN LEVEL 3 FAIR VALUE MEASUREMENTS

The tables below include the reconciliation of changes to the balance sheet amounts (in thousands) for the years ended April 30 for financial instruments classified within Level 3 of the valuation hierarchy; this determination is based upon unobservable inputs to the overall fair value measurement (in thousands):

Fiscal Year 2015	**Commodity Derivatives**	**Segregated Funds, net of Current Portion**	**Total**
Beginning balance at May 1	$ (3,239)	$ 217	$ (3,022)
Transfers out of Level 3	48	–	48
Net realized and unrealized gain/(loss) included in earnings	(16,327)	–	(16,327)
Purchases	(7,880)	–	(7,880)
Settlements	(792)	(203)	(995)
Balance at April 30	$ (28,190)	$ 14	$ (28,176)

Fiscal Year 2014	**Commodity Derivatives**	**Segregated Funds, net of Current Portion**	**Total**
Beginning balance at May 1	$ (20,251)	$ 4,031	$ (16,220)
Transfers out of Level 3	20,795	–	20,795
Net realized and unrealized gain/(loss) included in earnings	(927)	–	(927)
Purchases	(1,503)	–	(1,503)
Settlements	(1,353)	(3,814)	(5,167)
Balance at April 30	$ (3,239)	$ 217	$ (3,022)

Realized and unrealized gains and losses included in earnings identified above are included in wholesale revenues, power purchased, fuel used in electric generation or investment income, as appropriate, in the accompanying Combined Statements of Net Revenues. The transfers out of Level 3 for each year primarily represent derivative positions for which the maturity date has moved to within a time frame such that there are published price curves available to use for performing the valuations.

FAIR VALUE DISCLOSURES

U.S. GAAP requires disclosure of the estimated fair value of certain financial instruments and the methods and significant assumptions used to estimate their fair values. Many but not all of the financial instruments are recorded at fair value on the accompanying Combined Balance Sheets. Financial instruments held by SRP are discussed below.

Financial instruments for which fair value approximates carrying value: Certain financial instruments that are not carried at fair value on the accompanying Combined Balance Sheets are carried at amounts that approximate fair value due to their short-term nature and generally negligible credit risk. The instruments include receivables, accounts payable, customers' deposits, other current liabilities and commercial paper. The carrying amount of commercial paper approximates fair value because of its short-term maturity and pricing confirmed through independent sources.

Financial instruments for which fair value does not approximate carrying value: SRP presents long-term debt at carrying value on the accompanying Combined Balance Sheets. The collective fair value of the District's revenue bonds and the Desert Basin Lease-Purchase Agreement, including the current portion, was estimated by using pricing scales from independent sources. As of April 30, 2015 and 2014, the carrying amounts, including current portion and accrued interest, were $4.0 billion and $4.1 billion, respectively, and the estimated fair values were $4.3 billion and $4.4 billion, respectively. These estimated fair values are classified as Level 2 in the fair value hierarchy. (See Note [7], LONG-TERM DEBT, for further discussion of these items.)

[7] LONG-TERM DEBT AND CAPITAL LEASE OBLIGATION:

Long-term debt consists of the following at April 30 (in thousands):

	Interest Rate	2015	2014
Revenue bonds			
2004 Series A (mature 2015 – 2024)	4.00 – 5.00%	$ 49,670	$ 63,185
2005 Series A (mature 2027 – 2035)	4.75 – 5.00%	327,090	327,090
2006 Series A (mature 2033 – 2037)	5.00%	296,000	296,000
2008 Series A (mature 2016 – 2038)	5.00%	816,650	816,650
2009 Series A (mature 2014 – 2039)	2.75 – 5.00%	650,430	669,180
2009 Series B (mature 2014 – 2020)	3.00 – 4.50%	211,940	245,545
2010 Series A (mature 2040 – 2041)	4.839%	500,000	500,000
2010 Series B (mature 2014 – 2027)	2.00 – 5.00%	207,335	216,785
2011 Series A (mature 2013 – 2030)	2.00 – 5.00%	371,915	392,640
2012 Series A (mature 2029 – 2031)	5.00%	236,185	236,185
Total revenue bonds		3,667,215	3,763,260
Unamortized bond premium		138,545	154,442
Total revenue bonds outstanding		3,805,760	3,917,702
Commercial paper		125,000	125,000
Total long-term debt		3,930,760	4,042,702
Less: Current portion of long-term debt		(106,960)	(96,045)
Total long-term debt, net of current		$ 3,823,800	$ 3,946,657

The annual maturities of long-term debt (excluding unamortized bond discount/premium) as of April 30, 2015, due in fiscal years ending April 30, are as follows (in thousands):

	Revenue Bonds
2016	$ 106,960
2017	100,850
2018	102,880
2019	94,335
2020	93,710
Thereafter	3,168,480
Total	$ 3,667,215

REVENUE BONDS

Revenue bonds are secured by a pledge of, and a lien on, the revenues of the electric system, after deducting operating expenses, as defined in the amended and restated bond resolution, effective in January 2003, as amended (Bond Resolution). The Bond Resolution requires the District to charge and collect revenues sufficient to fund the debt reserve account and pay operating expenses, debt service, and all other charges and liens payable out of revenues and income. Under the terms of the Bond Resolution, the District makes debt service deposits to a non-trusteed segregated fund. Included in segregated funds in the accompanying Combined Balance Sheets are $179.6 million and $179.7 million of debt-service-related funds as of April 30, 2015 and 2014, respectively. Additionally, the Bond Resolution requires the District to maintain a debt service coverage ratio of 1.1 or greater on outstanding revenue bonds. To be eligible to issue additional revenue bonds, the District must anticipate sufficient revenues to maintain that ratio post-issuance. For the years ended April 30, 2015 and 2014, the debt service coverage ratio was 3.21 and 3.36, respectively. A substantial portion of the revenue bonds are callable by the District 10 years after issuance.

In October 2010, the District issued $500.0 million 2010 Series A Electric System Revenue Bonds as federally taxable, direct payment "Build America Bonds." Subject to the District's compliance with certain provisions of the ARRA and federal budget sequestration, the District expects to receive cash subsidy payments from the United States Treasury equal to 35% of the interest payable on the 2010 Series A Bonds over the term of the 2010 Series A Bonds. The District recorded $7.9 million and $7.8 million for cash subsidy earned from the United States Treasury for the years ending April 30, 2015 and 2014, respectively. The accrual for subsidy payments was $2.6 million as of April 30, 2015 and 2014. Cash subsidy earned is included in the Combined Statements of Net Revenues as a reduction to interest on bonds, net. Interest, Build America Bonds subsidy payments, and the amortization of the bond discount, premium, and issue expense on the various issues result in an effective rate of 4.31% over the remaining term of the bonds.

Due to federal budget sequestration, effective March 2013 the Internal Revenue Service published guidance stating that subsidy amounts claimed by Build America Bonds issuers will be reduced by 8.7% of the amount budgeted for such payments. The reduction rate was applied until September 30, 2013. After September 30, 2013, the Internal Revenue Service changed the reduction rate to 7.2%. The 7.2% reduction rate was applied to payments processed on or after October 1, 2013, and on or before September 30, 2014. Subsequently, the reduction rate was increased to 7.3%. This reduction rate applies to payments processed on or after October 1, 2014, and on or before September 30, 2015. The reduction rate will be applied unless and until a law is enacted that cancels or otherwise impacts the sequester, at which time the sequestration rate is subject to change. Accordingly, the District's January 1, 2014, and July 1, 2014, subsidy payments, which it received on December 10, 2013, and June 10, 2014, respectively, were each reduced by 7.2%, and the District's January 1, 2015, and July 1, 2015, subsidy payments, which it received on December 24, 2014, and June 9, 2015, were reduced by 7.3%. The District receives subsidy amounts semiannually, with the next payment scheduled for January 1, 2016.

In October 2013, the District redeemed $50.2 million 2002 Series C Electric System Refunding Revenue Bonds with cash from the District's General Fund. The General Fund represents the District's cash and investments that are not legally restricted or Board designated for specific purposes.

In June 2015, the District issued $924.5 million 2015 Series A Electric System Revenue Bonds at an average effective interest rate of 3.95 percent. $636.9 million of the proceeds were used to fund an externally trusteed irrevocable escrow to defease $49.7 million of outstanding 2004 Series A Revenue Bonds, $215.5 million of outstanding 2005 Series A Revenue Bonds, and $216.0 million of outstanding 2006 series A Revenue Bonds (the Refunded Bonds), and to purchase $75.8 million of outstanding 2005 Series A Revenue Bonds, and $80.0 million of outstanding 2006 Series A Revenue Bonds (the Purchased Bonds). The funds in the escrow were applied to interest payments occurring after the sale and to the redemption prices of the Refunded Bonds upon their call date of June 22, 2015. The remaining proceeds were used to fund the costs of issuance and to fund capital improvements of the District. The Refunded Bonds and Purchased Bonds will be removed from SRP's fiscal year 2016 Balance Sheet.

As of April 30, 2015, the District had authorization to issue additional Electric System Revenue Bonds totaling $1.2

billion principal amount and Electric System Refunding Revenue Bonds totaling $5.0 billion principal amount.

As of June 2, 2015, after the District issued 2015 Series A bonds and refunded 2004 Series A and 2006 Series A bonds and a portion of 2005 Series A bonds, the District has authorization to issue additional Electric System Revenue Bonds totaling $868.4 million principal amount and Electric System Refunding Revenue Bonds totaling $4.4 billion principal amount.

FINANCE LEASE

In December 2003, the District entered into a lease-purchase agreement (Desert Basin Lease-Purchase Agreement) with Desert Basin Independent Trust (DBIT) to finance the acquisition of the Desert Basin Generating Station (Desert Basin), located in central Arizona. In a concurrent transaction, $282.7 million in fixed-rate Certificates of Participation (COPs) were issued pursuant to a Trust Indenture between U.S. Bank National Association, as trustee, and DBIT, to fund the acquisition of Desert Basin and other electric system assets of the District. Investors in the COPs obtained an interest in the lease payments made by the District to DBIT under the Desert Basin Lease-Purchase Agreement. Due to the nature of the Desert Basin Lease-Purchase Agreement, the District recorded a lease-finance liability to DBIT with the same terms as the COPs. In December 2013, the District redeemed $137.9 million COPs with cash from the District's General Fund. After the redemption, no COPs remain outstanding.

CAPITAL LEASE OBLIGATION

In May 2008, the District entered into a 20-year power purchase agreement to purchase energy from a 575 megawatt (MW) simple-cycle, natural-gas peaking facility. The commercial operation date of the facility was May 1, 2011. Upon expiration of the contract and with proper notice, the District may renew the agreement for another 10 years, subject to certain conditions. Under the agreement, the District will pay a capacity charge, operation and maintenance costs, and property taxes. The District is also obligated to provide the natural gas needed to operate the facility. The capacity charge is paid monthly and will total approximately $51.9 million yearly. The District has concluded that this power purchase agreement is a capital lease. Accordingly, a capital lease asset and corresponding liability were recorded on May 1, 2011, in the amount of $517.0 million. The capital lease asset is being amortized on the straight-line basis over the original 20-year term of the contract. Accumulated amortization as of April 30, 2015 and 2014, is $102.3 million and $76.5 million, respectively.

Future minimum lease payments, excluding executory costs, under the capital lease as of April 30, 2015, are as follows (*in thousands*):

2016	$ 51,867
2017	51,867
2018	51,867
2019	51,867
2020	51,867
Thereafter	570,539
Total minimum lease payments	829,874
Less: Imputed interest	(350,501)
Less: Imputed lessor profit on executory costs	(12,995)
Less: Current portion of capital lease obligation	(15,293)
Long-term capital lease obligation	$ 451,085

[8] COMMERCIAL PAPER AND CREDIT AGREEMENTS:

The District is authorized by the Board to issue up to $500.0 million in commercial paper. The District had $50.0 million Series C Commercial Paper outstanding at April 30, 2015 and 2014, and an additional $75.0 million Series D-1 Commercial Paper. At April 30, 2015 and 2014, the Series C issue had an average weighted interest rate to the District of 0.07% and 0.08%, respectively. At April 30, 2015 and 2014, the Series D-1 issue had an average weighted interest rate to the District of 0.16% and 0.13%, respectively. The commercial paper matures not more than 270 days from the date of issuance and is an unsecured obligation of the District.

The District has two revolving line-of-credit agreements, $100.0 million and $400.0 million. Both agreements support the $125.0 million of outstanding commercial paper at April 30, 2015 and 2014. The $100.0 million revolving credit agreement expires on May 16, 2017, and the $400.0 million revolving credit agreement expires on June 25, 2018. SRP has classified the commercial paper program as long-term debt in the accompanying Combined Balance Sheets at April 30, 2015 and 2014. The additional $375.0 million in credit available under the two lines of credit may be used to support the issuance of additional commercial paper or for other general corporate purposes.

In May 2015, the District issued an additional $100.0 million Series D-1 Commercial Paper at an average rate of 0.19 percent.

The revolving line-of-credit agreements contain various conditions precedent to borrowings that include, but are not limited to, compliance with the covenants set forth in the agreements, the continued accuracy of representations and warranties, no existence of default and maintenance of certain investment grade ratings on the District's revenue bonds. The District was in compliance with the various covenants at April 30, 2015 and 2014. The District has never borrowed under the agreements. Alternative sources of funds to support the commercial paper program include existing funds on hand or the issuance of alternative debt, such as revenue bonds.

[9] EMPLOYEE BENEFIT PLANS AND INCENTIVE PROGRAMS:

DEFINED BENEFIT PENSION PLAN AND OTHER POST-RETIREMENT BENEFITS

SRP's Employees' Retirement Plan (the Plan) covers substantially all employees. The Plan is funded entirely from SRP contributions and the income earned on invested Plan assets. SRP contributed $60.0 million in fiscal year 2015 and made no contribution in fiscal year 2014.

SRP provides a non-contributory defined benefit medical plan for retired employees and their eligible dependents (contributory for employees hired January 1, 2000, or later) and a non-contributory defined benefit life insurance plan for retired employees. Employees are eligible for coverage if they retire at age 65 or older with at least five years of vested service under the Plan (ten years for those hired January 1, 2000, or later), or at any time after attainment of age 55 with a minimum of ten years of vested service under the Plan (20 years for those hired January 1, 2000, or later). The funding policy is discretionary.

U.S. GAAP requires employers to recognize the overfunded or underfunded positions of defined benefit pension and other post-retirement plans in their balance sheets. Any actuarial gains and losses, prior service costs, and transition assets or obligations must be recorded on the balance sheet with an offset to accumulated other comprehensive income until the amounts are amortized as a component of net periodic benefit costs.

The Board has authorized the District to collect future amounts associated with the pension and other post-retirement plan liabilities as part of the pricing process. The District established a regulatory asset for the amounts otherwise chargeable to accumulated other comprehensive income that are expected to be recovered through prices in future periods. The changes in actuarial gains and losses, prior service costs, and transition assets or obligations pertaining to the regulatory asset are recognized as an adjustment to the regulatory asset or liability accounts, as these amounts are recognized as components of net periodic pension costs each year. The District's amortization amounts for fiscal year 2015 are $(0.1) million for prior service cost and $47.4 million for net actuarial loss. The District's amortization amounts for fiscal year 2014 are $1.3 million for prior service cost and $67.5 million for net actuarial loss.

The following tables outline changes in benefit obligations, plan assets, the funded status of the plans and amounts included in the accompanying Combined Financial Statements (in thousands):

	Pension Benefits		Post-retirement Benefits	
	2015	**2014**	**2015**	**2014**
Change in benefit obligation				
Benefit obligation at beginning of year	$ 1,988,878	$ 2,014,039	$ 729,780	$ 742,787
Service cost	57,895	61,939	15,001	16,750
Interest cost	94,613	84,504	34,760	31,205
Actuarial loss (gain)	125,878	(102,150)	15,157	(37,958)
Benefits paid	(75,705)	(69,454)	(23,999)	(23,004)
Benefit obligation at end of year	$ 2,191,559	$ 1,988,878	$ 770, 699	$ 729,780
Change in plan assets				
Fair value of plan assets at beginning of year	$ 1,751,064	$ 1,658,265	$ –	$ –
Actual return on plan assets	171,216	162,253	–	–
Employer contributions	60,000	–	23,999	23,004
Benefits paid	(75,704)	(69,454)	(23,999)	(23,004)
Fair value of plan assets at end of year	1,906,576	1,751,064	–	–
Funded status at end of year	$ (284,983)	$ (237,814)	$ (770,699)	$ (729,780)
Amounts recognized in Combined Balance Sheets:				
Other current liabilities	$ –	$ –	$ (26,024)	$ (26,152)
Accrued post-retirement liability	(284,983)	(237,814)	(744,675)	(703,628)
Net asset (liability) recognized	$ (284,983)	$ (237,814)	$ (770,699)	$ (729,780)
Amounts recognized as a regulatory asset:				
Prior service cost (credit)	$ 176	$ 348	$ (5,981)	$ (6,251)
Net actuarial loss (gain)	691,988	639,249	216,455	210,788
Net regulatory asset	$ 692,164	$ 639,597	$ 210,474	$ 204,537

The following table represents the amortization amounts expected to be recognized during the fiscal year ending April 30, 2016 (in thousands):

	Pension Benefits	Post-retirement Benefits
Prior service cost/(credit)	$ 48	$ (330)
Net actuarial	$ 38,073	$ 8,755

The accumulated benefit obligation for pension benefits was $1.9 billion and $1.7 billion as of April 30, 2015 and 2014, respectively.

SRP internally funds its other post-retirement benefits obligation. At April 30, 2015 and 2014, $695.6 million and $653.4 million of segregated funds, respectively, were designated for this purpose.

The weighted average assumptions used to calculate actuarial present values of benefit obligations at April 30 were as follows:

	Pension Benefits		Post-retirement Benefits	
	2015	2014	2015	2014
Discount rate	4.36%	4.85%	4.36%	4.85%
Rate of compensation increase	4.69%	4.00%	N/A	N/A

Weighted average assumptions used to calculate net periodic benefit costs were as follows:

	Pension Benefits		Post-retirement Benefits	
	2015	2014	2015	2014
Discount rate	4.85%	4.27%	4.85%	4.27%
Expected return on Plan assets	8.25%	8.25%	N/A	N/A
Rate of compensation increase	4.00%	4.00%	N/A	N/A

A 6.50% annual increase in per capita costs of health care benefits was assumed during 2015; these rates were assumed to decrease uniformly until equaling 5% in all future years.

The components of net periodic benefit costs for the years ended April 30 are as follows (in thousands):

	Pension Benefits		Post-retirement Benefits	
	2015	2014	2015	2014
Service cost	$ 57,895	$ 61,938	$ 15,001	$ 16,750
Interest cost	94,613	84,504	34,760	31,205
Expected return on Plan assets	(136,018)	(129,627)	–	–
Amortization of transition obligation	–	–	–	(1)
Amortization of net actuarial loss	37,940	54,329	9,490	13,206
Amortization of prior service cost	172	1,620	(270)	(270)
Net periodic benefit cost	$ 54,602	$ 72,764	$ 58,981	$ 60,890

Assumed health care cost trend rates have a significant effect on the amounts reported for health care plans. A one-percentage-point change in the assumed health care cost trend rates would have the following effect (in thousands):

	One Percentage Point Increase	One Percentage Point Decrease
Effect on total service cost and interest cost components	$ 9,846	$ (7,590)
Effect on post-retirement benefit obligation	$ 146,434	$ (103,952)

PLAN ASSETS

The Board has established an investment policy for Plan assets and has delegated oversight of such assets to a compensation committee (the Committee). The investment policy sets forth the objective of providing for future pension benefits by targeting returns consistent with a stated tolerance of risk. The investment policy is based on analysis of the characteristics of the Plan sponsors, actuarial factors, current Plan condition, liquidity needs, and legal requirements. The primary investment strategies are diversification of assets, stated asset allocation targets and ranges, and external management of Plan assets. The Committee determines the overall target asset allocation ratio for the Plan and defines the target asset allocation ratio deemed most appropriate for the needs of the Plan and the risk tolerance of the District.

The market value of investments (reflecting returns, contributions, and benefit payments) within the Plan trust appreciated 9.90% during fiscal year 2015, compared to an increase of 11.01% during fiscal year 2014. Changes in the Plan's funded status affect the assets and liabilities recorded on the balance sheet in accordance with FASB authoritative guidance. Due to the District's regulatory treatment, the recognition of funded status is offset by regulatory assets or liabilities and is recovered through prices. The Pension Protection Act (PPA) of 2006 establishes new minimum funding standards and restricts plans underfunded by more than 20% from adopting amendments that increase plan liabilities unless they are funded immediately. In December 2008, the Worker, Retiree, and Employer Recovery Act (WRERA) was enacted. Among other provisions, the WRERA provides temporary funding relief to defined benefit plans during the current economic downturn. The Preservation of Access to Care for Medicare Beneficiaries and Pension Relief Act of 2010 (PACMBPRA) was signed into law during fiscal year 2011. During fiscal year 2013, the Moving Ahead for Progress in the 21st Century Act (MAP-21) was passed, which included a provision related to pension funding. All three acts subsequent to the passage of the PPA, WRERA, PACMBPRA, and MAP-21 will favorably affect the level of minimum required contributions.

The Plan's weighted-average asset allocations are as follows:

	Target Allocations	2015	2014
Equity securities	65.0%	61.2%	66.7%
Debt securities	25.0%	29.7%	24.5%
Real estate	10.0%	9.1%	8.8%
Total	100.0%	100.0%	100.0%

The investment policy, as authorized by the Board, allows management to reallocate Plan assets at any time within a tolerance range up to plus or minus 5% from the target asset allocation which allows for flexibility in managing the assets based on prevailing market conditions and does not require automatic rebalancing if the actual allocation strays from the target allocation.

FAIR VALUE OF PLAN ASSETS

The following table sets forth the fair value of Plan assets, by asset category, at April 30, 2015 (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Cash and cash equivalents	$ 38,876	$ 4,856	$ –	$ 43,732
Mutual funds	391,137	–	–	391,137
U.S. government securities	–	8,068	–	8,068
Corporate bonds	–	446,328	–	446,328
Corporate stocks	325,512	–	–	325,512
Commingled funds	–	292,688	224,844	517,532
Real estate	–	–	174,267	174,267
Total assets	$ 755,525	$ 751,940	$ 399,111	$ 1,906,576

The following table sets forth the fair value of Plan assets, by asset category, at April 30, 2014 (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Cash and cash equivalents	$ 19,058	$ 25,903	$ –	$ 44,961
Mutual funds	380,981	–	–	380,981
U.S. government securities	–	106,628	–	106,628
Corporate bonds	–	222,809	–	222,809
Corporate stocks	408,820	–	–	408,820
Commingled funds	–	160,705	269,127	429,832
Real estate	–	–	155,978	155,978
Exchange traded derivatives	25,734	–	–	25,734
OTC derivatives	–	79,265	–	79,265
Exchange traded derivative liabilities	(24,409)	–	–	(24,409)
OTC derivative liabilities	–	(79,535)	–	(79,535)
Total assets	$ 810,184	$ 515,775	$ 425,105	$ 1,751,064

For a description of the fair value hierarchy, refer to Note (6), FAIR VALUE MEASUREMENTS.

VALUATION METHODOLOGIES

Real estate: Real estate commingled funds are funds with a direct investment in a pool of real estate properties. These funds are valued by investment managers on a periodic basis using pricing models that use independent appraisals from sources with professional qualifications. Since these valuation inputs are not highly observable, real estate investments have been categorized as Level 3 investments. The valuations of the real estate funds are sensitive to market factors outside the control of the Plan, including interest rate levels and economic activity. The valuations, although done quarterly by independent qualified appraisers, may vary due to these factors.

Exchange traded derivatives: The fair values of exchange traded options and futures are priced based on inputs using quoted prices in active markets using observable inputs. Observable inputs reflect the assumptions market participants would use in pricing the asset or liability developed based on market data obtained from sources independent of the reporting entity. Therefore, these investments have been categorized as Level 1. As of April 30, 2015, the Plan only held exchange traded futures, which are settled daily. Therefore, no market value is reported for them.

OTC derivatives: The fair values of OTC options, forwards, swaptions, and swaps are priced based on inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly or indirectly through corroboration with observable market data. Therefore, these investments have been categorized as Level 2 in the fair value hierarchy. As of April 30, 2015, the Plan no longer held these types of derivatives.

For an explanation of the valuation methodologies used to determine fair value of the assets of the Plan that are not listed above, refer to Note (6), FAIR VALUE MEASUREMENTS.

CHANGES IN LEVEL 3 FAIR VALUE MEASUREMENTS

The table below includes the reconciliation of changes to the balance sheet amounts for the years ended April 30 for financial instruments classified within Level 3 of the valuation hierarchy; this determination is based upon unobservable inputs to the overall fair value measurement:

Plan Assets (in thousands)	**2015**	**2014**
Beginning balance at May 1	$ 425,105	$ 228,983
Actual return on plan assets relating to assets still held at period end	52,857	25,283
Purchases	–	170,839
Settlements	(78,851)	–
Balance at April 30	$ 399,111	$ 425,105

LONG-TERM RATE OF RETURN

The expected return on Plan assets is based on a review of the Plan asset allocations and consultations with a third-party investment consultant and the Plan actuary, considering market and economic indicators, historical market returns, correlations and volatility, and recent professional or academic research.

EMPLOYER CONTRIBUTIONS

SRP expects to contribute $60.0 million to the Plan over the next year.

BENEFITS PAYMENTS

SRP expects to pay benefits in the amounts as follows (in thousands):

	Pension Benefits	**Post-retirement Benefits**	
		Before Subsidy*	**Net**
2016	$ 83,659	$ 27,483	$ 26,024
2017	88,205	29,190	28,181
2018	93,073	30,692	29,575
2019	98,148	32,214	30,989
2020	103,541	33,752	32,417
2021 through 2025	**596,721**	**191,213**	**182,966**

**Estimated future benefit payments, including prescription drug benefits, prior to federal drug subsidy receipts expected as a result of the Medicare Prescription Drug, Improvement and Modernization Act of 2003.*

DEFINED CONTRIBUTION PLAN

SRP's Employees' 401(k) Plan (the 401(k) Plan) covers substantially all employees. The 401(k) Plan receives employee pre-tax and post-tax contributions and partial employer matching contributions. Employees who have one year of service in which they have worked at least 1,000 hours and who are also contributing to the 401(k) Plan are eligible to receive partial employer matching contributions of $0.90 on every dollar contributed up to the first 6% of their base pay that they contribute to the 401(k) Plan. Employer matching contributions to the 401(k) Plan were $18.2 million and $16.8 million during fiscal years 2015 and 2014, respectively.

EMPLOYEE PERFORMANCE INCENTIVE COMPENSATION PROGRAM

The Employee Performance Incentive Compensation (EPIC) program, a cash based incentive program, is approved by the Board each year. EPIC covers substantially all regular employees, and is based on the achievement of pre-established targets for each fiscal year. The total compensation expense recognized for the EPIC program for fiscal years 2015 and 2014 was $24.6 million and $22.6 million, respectively.

EMPLOYEE SICK LEAVE PLAN

The SRP Employee Sick Leave Plan provides payment to employees for unused sick leave. Employees accumulate sick days at a rate of one day per month. The accumulation, up to the personal maximum, can be carried forward year after year. For most employees, the personal maximum is 720 hours. For sick leave hours accumulated in excess of the personal maximum, a lump sum payment at half pay is made annually in January of each year based on the hourly rate at time of payment, and the accumulated sick leave is then returned to the personal maximum. Upon death or retirement, payment is made for any unused sick leave hours. The payments for retirement or death are based on the hourly rate of pay at retirement or death. SRP has an accrual for unpaid sick leave of approximately $50.0 million and $52.0 million at April 30, 2015 and 2014, respectively. The accrual is determined actuarially based on various assumptions, including future pay raises, discount rate, and the amount of the accrual that will ultimately be paid out.

[10] INTERESTS IN JOINTLY OWNED ELECTRIC UTILITY PLANTS AND TRANSMISSION FACILITIES:

The District has entered into various agreements with other electric utilities for the joint ownership of electric generating and transmission facilities. Each participating owner in these facilities must provide for the cost of its ownership share. The District's share of expenses of the jointly owned plants and transmission facilities is included in other operating expenses and maintenance in the accompanying Combined Statements of Net Revenues.

The following table reflects the District's ownership interests in jointly owned facilities at electric utility plants as of April 30, 2015 (in thousands):

Generating Station	Ownership Share	Plant in Service	Accumulated Depreciation	Construction Work In Progress
Four Corners (NM) (Units 4 & 5)	10.00%	$ 135,803	$ (115,143)	$ 2,061
Navajo (AZ) (Units 1, 2 & 3)	21.70%	351,417	(330,267)	10,552
Hayden (CO) (Unit 2)	50.00%	143,358	(124,095)	14,329
Craig (CO) (Units 1 & 2)	29.00%	297,852	(292,554)	13,216
Mesquite Common	50.00%	75,279	(3,259)	–
PVNGS (AZ) (Units 1, 2 & 3)	17.49%	1,301,075	(1,043,284)	34,526
		$ 2,304,784	$ (1,908,602)	$ 74,684

The following table reflects the District's investment in jointly owned transmission facilities as of April 30, 2015 (in thousands):

Transmission Facility	Plant in Service	Accumulated Depreciation	Construction Work In Progress
Mead Phoenix	$ 53,620	$ (16,777)	$ 190
Southwest Valley	78,988	(14,734)	229
Southeast Valley	292,144	(20,891)	2,148
Morgan-Pinnacle Peak	68,596	(4,085)	471
El Dorado	11,558	(4,527)	1,103
Southern Transmission	72,304	(33,194)	447
Mesquite	23,797	(701)	–
ANPP	70,829	(25,556)	2,326
	$ 671,836	$ (120,465)	$ 6,914

The District's ownership interests in the jointly owned transmission facilities vary by facility and for the various projects within each facility.

[11] VARIABLE INTEREST ENTITIES:

SRP follows guidance that defines a variable interest entity (VIE) as a legal entity whose equity owners do not have sufficient equity at risk or lack certain characteristics of a controlling financial interest in the entity. This guidance identifies the primary beneficiary as the variable interest holder that has the power to direct the activities that most significantly affect the VIE's economic performance (power criterion) and has the obligation to absorb losses or the right to receive benefits from the VIE (losses/benefits criterion). The primary beneficiary is required to consolidate the VIE unless specific exceptions or exclusions are met. SRP considers both qualitative and quantitative factors to form a conclusion whether it, or another interest holder, meets the power criterion and the losses/benefits criterion. SRP performs ongoing reassessments of its VIEs to determine if the primary beneficiary changes each reporting period.

UNCONSOLIDATED VIEs

While SRP is not required to consolidate any VIE as of April 30, 2015 or 2014, it held variable interests in certain VIEs as described below.

In May 2008, the District entered into a 20-year power purchase agreement to purchase energy from a 575 MW simple-cycle natural-gas peaking facility. The District has concluded that this power purchase agreement is a capital lease. The District has also determined that it is not the primary beneficiary of this VIE since it does not control operations and maintenance, which it believes are the primary activities that most significantly affect the economic activities of the entity. See further discussion in Note (7), LONG-TERM DEBT AND CAPITAL LEASE OBLIGATION.

In prior years, the District entered into various long-term power purchase agreements with developing renewable energy generation facilities that extend for periods of 20 to 30 years. The District is receiving the power and renewable energy credits from these facilities. The capacity of all the facilities combined is approximately 241 MW. The amounts that the District paid to these projects were $102.1 million and $92.5 million for fiscal years 2015 and 2014, respectively. With the exception of projects for which the District is obligated to pay operating and maintenance expenses, the District is obligated to pay only for actual energy delivered and will have no obligation with respect to any facilities that do not start commercial operations. Some of these agreements include a price adjustment clause that will affect the future cost. There are no minimum payment obligations under these agreements. The District has concluded that it is not the primary beneficiary of these VIEs since it does not control operations and maintenance, which it believes are the primary activities that most significantly affect the economic activities of the entity.

The District formed a partnership during fiscal year 2010 to market long-term water storage credits. The District made net capital contributions of $2.9 million and $1.4 million to the partnership and carried $8.7 million and $5.6 million of investment in the partnership in fiscal years 2015 and 2014, respectively. The District has a future maximum exposure up to a $25.0 million contribution limit. The primary risks associated with this VIE relate to the marketing of the water storage credits. The District has concluded that it is not the primary beneficiary of this VIE since it does not have power to direct the activities related to the marketing of the long-term water storage credits, which represent the most significant economic activities of the VIE.

[12] COMMITMENTS:

PURCHASED POWER AND FUEL SUPPLY

The District had various firm, non-cancelable purchase commitments at April 30, 2015, which are not recognized in the accompanying Combined Balance Sheets. The following table presents actual payments and estimated future payments pertaining to firm purchase commitments with remaining terms greater than one year (in millions):

	Purchase Commitments					
	2016	**2017**	**2018**	**2019**	**2020**	**Thereafter**
Purchase power contracts	$ 33.8	$ 34.2	$ 34.6	$ 35.1	$ 35.6	$ 584.3
Fuel supply contracts	280.3	202.7	199.2	188.1	149.5	547.3
Total	$ 314.1	$ 236.9	$ 233.8	$ 223.2	$ 185.1	$ 1,131.6

GAS PURCHASE AGREEMENT

In October 2007, the District entered into a 30-year gas purchase agreement with Salt Verde Financial Corporation (SVFC), an Arizona nonprofit corporation formed for the primary purpose of supplying natural gas to the District. Under the agreement, the District is committed to purchase 10,270,000 MMBtus (millions of British thermal units) in fiscal year 2016, 10,420,000 MMBtus each fiscal year 2017 through 2020, and 187,560,000 MMBtus over the balance of the term. These purchases are expected to supply approximately 20% of its projected natural-gas requirements needed to serve retail customers over the remainder of the 30-year period. The District receives a discount off market prices and is obligated to pay only for gas delivered. Payments, net of discount, to SVFC under the agreement were $35.0 million and $29.7 million in fiscal years 2015 and 2014, respectively. The agreement also provides for payment from SVFC to the District of certain excess cash resulting from a portion of SVFC's investment income, which effectively reduces the price the District pays for the gas. The excess cash amounts received by the District from SVFC totaled $3.1 million in both fiscal years 2015 and 2014. SVFC is a related party to the District.

OPERATING LEASES

The District entered into various operating leases to facilitate the operations of Springerville Generating Station (Springerville) Unit 4, a 400 MW gas-fired plant owned by the District and operated by Tucson Electric Power Company (TEP). Total payments under the agreements to TEP and other parties were $13.3 million and $13.5 million in fiscal years 2015 and 2014, respectively. Minimum payments under these agreements are estimated to be $9.8 million in fiscal years 2016 through 2020, and $237.8 million thereafter. The leases expire in various years from 2015 through 2106.

[13] CONTINGENCIES:

NUCLEAR INSURANCE

Under existing law, public liability claims arising from a single nuclear incident are limited to $13.5 billion. PVNGS participants insure for this potential liability through commercial insurance carriers to the maximum amount available ($375.0 million) with the balance covered by an industry-wide retrospective assessment program as required by the Price-Anderson Act. If losses at any nuclear power plant exceed available commercial insurance, the District could be assessed retrospective premium adjustments. The maximum assessment per reactor per nuclear incident under the retrospective program is $127.3 million, including a 5% surcharge applicable in certain circumstances, but not more than $19.0 million per reactor may be charged in any one year for each incident. Based on the District's ownership share of PVNGS, the maximum potential assessment would be $66.8 million, including the 5% surcharge, but would be limited to $10.0 million per incident in any one year.

PVNGS participants also maintain "all risk" (including nuclear hazards) insurance for property damage to, and decontamination of, property at PVNGS in the aggregate amount of $2.8 billion, a substantial portion of which must first be applied to stabilization and decontamination. The District also secured insurance against portions of any increased cost of generation or purchased power and any business interruption resulting from a sudden and unforeseen accidental outage of any of the three units. The coverage for property damage, decontamination, and replacement power is provided by Nuclear Electric Insurance Limited (NEIL). The District is subject to retrospective assessments under all NEIL policies if NEIL's losses in any policy year exceed accumulated funds. The maximum amount of retrospective assessments the District could incur under the NEIL policies totals approximately $11.8 million. The insurance coverage discussed in this and the previous paragraph is subject to certain policy conditions and exclusions.

SPENT NUCLEAR FUEL

Under the Nuclear Waste Policy Act of 1982, the District was required to pay $0.001 per kilowatt-hour on its share of net energy generation at PVNGS to the U.S. Department of Energy (DOE) through April 30, 2015. However, to date, for various reasons, the DOE has not constructed a site for the storage of spent nuclear fuel. Accordingly, Arizona Public Service Company (APS), the operating agent for PVNGS, has constructed an on-site dry cask storage facility to receive and store PVNGS spent fuel. PVNGS has sufficient capacity at its on-site spent fuel storage installation to be able to store all of the nuclear fuel that will be spent during the first operating license period which ends in December 2027. In addition, PVNGS has sufficient capacity to store a portion of the fuel that will be spent during the period of extended operation, which will end in December 2047. Potentially, and depending on how the NRC rules on the future unloading of spent fuel pools, PVNGS could use high capacity storage casks to store the balance of any fuel spent during the extended license period. The on-site facility stored its first cask in March 2003. Effective May 15, 2014, the per kilowatt-hour charge on energy generation at PVNGS was reduced to zero. A similar charge could be reinstated in the future.

The District's share of on-site interim storage at PVNGS is estimated to be $73.3 million for costs to store spent nuclear fuel from inception through the life of the plant. These costs are recovered through the District's base rates as a component of the system benefit charge. At April 30, 2015 and 2014, the District's accrued spent fuel storage cost was $23.6 million and $23.3 million, respectively, and is included in deferred credits and other non-current liabilities on the accompanying Combined Balance Sheets.

COAL SUPPLY

Kayenta Mine Permit Renewal: In 2008, the Office of Surface Mining, Reclamation and Enforcement (OSM) issued an Environmental Impact Statement (EIS) to allow Peabody Coal Company (Peabody) to include the Black Mesa Mine (which formerly served the Mohave Generating Station) in the permit for the Kayenta Mine (which serves NGS). Among other things, combining the two permits could eventually give Peabody access to shallower, high quality coal for NGS, which could reduce future costs to the NGS Participants and provide an additional source of coal. Under the administrative appeals process, numerous appeals of the permit decision were filed, and a decision was issued that the process OSM had followed to issue the permit was inadequate. In response to the decision, Peabody filed an application for a permit renewal for the Kayenta Mine. On January 6, 2012, the OSM approved a five-year renewal of the permit through July 6, 2015. In February 2012, three separate appeals of the renewal were filed by various environmental and tribal groups, following which the District successfully intervened in the matter. Although an Administrative Law Judge (ALJ) issued a decision disposing of several of the claims in the appeals, certain claims were left for hearing. The proceedings were stayed pending discussions among the parties regarding the possible resolution of some of the remaining claims. A settlement agreement has been executed with all parties except the Black Mesa Trust (BMT) and The Forgotten People (TFP). The Administrative Law Judge subsequently dismissed all of the remaining requests for review by TFP and BMT. On August 30, 2014, TFP filed a Petition for Discretionary Review before the Interior Board of Land Appeals arguing that several issues were not sufficiently resolved or mooted by the settlement agreement. Peabody and OSM filed responses arguing that TFP has not alleged any errors in the ALJ's decision and therefore the petition should be denied. There has been no decision issued. Peabody recently filed a new application for a permit renewal for the Kayenta Mine which would, if approved, extend the permit from 2015 to 2020. The District cannot predict the outcome of this matter at this time.

Navajo Mine Permit: BHP Billiton Limited (BHP), through a subsidiary, BHP Navajo Coal Company (BNCC), operates the Navajo Coal Mine, which supplies coal to Four Corners Units 4 and 5. On December 30, 2013, BHP sold its ownership of BNCC to Navajo Transitional Energy Company, LLC (NTEC), a company formed by the Navajo Nation to own the Navajo Coal Mine and develop other energy projects. OSM finalized the transfer of the Surface Mining Control and Reclamation Act of 1977 (SMCRA) permit from BHP to NTEC. Several environmental groups filed a lawsuit challenging the mining permit and expanded operations. If this lawsuit is successful, it would result not only in an increased cost of mining operations, which would be passed on to the owners of Four Corners, but could result in the suspension or termination of mining activities. APS, as operating agent of Four Corners, is working with NTEC, which intervened in the lawsuit, to allow the expansion and continuation of the Navajo Coal Mine. On March 2, 2015, the Court ruled that OSM failed to adequately consider the combustion-related effects of NTEC's proposed expansion of operations at the Navajo Coal Mine and granted the environmental groups' Petition for Review. The Court ordered the parties to confer in an effort to reach an agreement with respect to the appropriate remedy. The parties were unable to reach an agreement, and as required by the order, the parties submitted briefs proposing an appropriate remedy. On April 6, 2015, the Court vacated OSM's approval of NTEC's Permit Revision Application pending OSM's compliance with the National Environmental Policy Act (NEPA), thereby suspending mining activities in a relatively small portion of the Navajo Coal Mine. On April 8, 2015, NTEC filed its Notice of Appeal of the Court's orders. NTEC also asked the Tenth Circuit for an emergency stay of the lower Court's orders arguing that even a brief, partial interruption in its mining operations could have "catastrophic" consequences for the Tribe. The Tenth Circuit denied NTEC's motion. OSM filed its notice of appeal on June 3, 2015. OSM and NTEC's appeals are consolidated. The Court has issued a briefing schedule in this matter. There remains sufficient coal in approved mining areas to supply coal to Four Corners Units 4 and 5 through July 2018. The District cannot predict the outcome of this lawsuit at this time.

Trapper Mine Permit: On February 27, 2013, Wild Earth Guardians (WEG) filed suit in the U.S. District Court for the District of Colorado against the Office of Surface Mining (OSM), Al Klein, the Western Regional Director of the OSM, and Secretary of the Interior Ken Salazar (Secretary) (the Complaint). In the Complaint, WEG alleges that the OSM violated NEPA and the Administrative Procedure Act (APA) by "unlawfully approving mining plans for the Colowyo and Trapper Mines in Colorado" and the plans of five other mines located in Montana, New Mexico and Wyoming. The District owns a 32.1% interest in Trapper Mining Inc. (Trapper), which owns the Trapper Mine. Trapper Mine serves Craig Generating Station, in which the District owns 29% of Units 1 and 2. WEG alleges, among other things, that the Secretary's approval of Trapper's 2009 modification to its existing mining plan (the 2009 Trapper Plan) violated NEPA and the APA on various grounds. WEG asked the Court to reverse the Secretary's approval of the 2009 Trapper Plan and enjoin Trapper from continuing its mining operations until OSM demonstrates compliance with NEPA and the APA when considering approval of the 2009 Trapper Plan. Trapper has intervened in the suit. Oral argument was held on April 24, 2015. On May 8, 2015, the Court ruled that OSM failed to comply with NEPA in approving the permit revisions for Trapper. However, the Court did not vacate the permit, on the understanding that all of the coal at issue already had been mined. Based on subsequent filings by Trapper correcting certain facts before the Court, it is possible that the Court could reconsider its decision not to vacate the permit. Trapper filed a notice of appeal of the Court's ruling with the Tenth Circuit on July 6, 2015, and continues mining a separately permitted area. The District cannot predict the outcome of this lawsuit at this time.

ENVIRONMENTAL

SRP is subject to numerous legislative, administrative and regulatory requirements at the federal, state and local levels, as well as lawsuits relative to air quality, water quality, hazardous waste disposal and other environmental matters. Such requirements have resulted, and will continue to result, in increased costs associated with the operation of existing properties. At April 30, 2015 and 2014, SRP accrued $34.3 million and $35.0 million, respectively, for environmental issues, on a non-discounted basis, which is included in deferred credits and other non-current liabilities on the accompanying Combined Balance Sheets. The following topics highlight some of the major environmental compliance issues affecting the District.

Water quality: Due to the nature of its business, from time to time the District is involved in various state and federal superfund matters. In September 2003, the EPA notified the District that it might be liable under the federal Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) as an owner and operator of a facility within the Motorola 52nd Street Superfund Site Operable Unit 3. The District completed the remedial investigation at the facility, and received a no further action letter from the EPA, but other potentially responsible parties are still undertaking remedial investigations and feasibility studies and the District could still be liable for past costs incurred and for future work to be conducted within the Superfund Site with regard to groundwater. At the adjacent West Van Buren Water Quality Assurance Revolving Fund Site, a state superfund site, the Roosevelt Irrigation District (RID) has sued the District and numerous other parties claiming that as a result of groundwater contamination, RID has been damaged in excess of $125.0 million. The District denies the allegations and intends to vigorously contest the claim. Although the District was temporarily dismissed from the lawsuit, the plaintiff, with new counsel, filed a Second Amended Complaint which named the District directly as a defendant again, along with a smaller number of potentially responsible parties than in the original complaint and First Amended Complaint. The District filed an Answer to the Second Amended Complaint. While the District is unable at this time to predict the outcome of these and other superfund matters, it believes it has recorded adequate reserves as part of its environmental reserves to cover expected liabilities related to these issues.

Air quality: Efforts to reduce emissions from fossil fuel power plants will substantially increase the cost of, and add to the difficulty of, siting, constructing and operating electric generating units. As a result of legislative and regulatory initiatives, the District is planning reductions in emissions of mercury and other pollutants at its coal-fired power plants, including plants located on the Navajo Reservation. In particular, under the terms of a consent agreement with the EPA, the District installed additional pollution control equipment at CGS at an approximate cost of $470 million.

The full significance of air-quality standards and emissions-reduction initiatives to the District in terms of costs and operational problems is difficult to predict, but recent regulatory actions mean that costly equipment will be added to units now in operation. In addition, the cost of fossil fuel purchased by the District may increase and permit fees may increase significantly, resulting in potentially material cost to the District as well as reduced generation. The District is assessing the risk of policy initiatives on its generation assets and is developing contingency plans to comply with future laws and regulations relating to renewable energy and restricting greenhouse gas (GHG) emissions. The District cannot predict the impact of such initiatives on the District at this time.

The District negotiated a Consent Order with the Arizona Department of Environmental Quality (ADEQ), pursuant to which the District will delay compliance with current Arizona limitations on mercury emissions until 2016, and instead implemented a control strategy designed to achieve a 70% reduction of mercury emissions at CGS on a facility-wide annual average basis beginning January 1, 2012, at an estimated annual cost of $2.4 million. Beginning April 2016, the District will be required to comply with the federal standards for mercury established by the Mercury and Air Toxics Standards (MATS) rule. The State has adopted backstop limitations that would remain in place if the federal rule is repealed or vacated. These standards match the current federal standards.

In February 2012, the EPA published its Mercury and Air Toxics Standards (MATS) rule, which establishes new emissions standards for trace minerals, acid gases, mercury and organic compounds from existing and new coal- and oil-fired power plants under the Clean Air Act (CAA). These standards were effective in April 2015, other than for facilities granted an extension under the CAA. Extension requests were granted for Coronado Generating Station (CGS) and Navajo Generating Station (NGS). The District has determined this rule will require new controls for mercury at the District-operated CGS and NGS facilities. The District is finalizing the control strategy at each plant and will permit and construct the selected strategy to meet the April 2016 deadline for compliance with the MATS mercury limit. The District does not anticipate additional controls will be required at any of the other coal-fired plants in which the District has an interest. On June 29, 2015, the Supreme Court ruled that the EPA's MATS rule did not consider the cost of the pollution regulations early in the rule-making process when determining whether regulation of electric generating units was "appropriate and necessary" under Section 112 of the CAA. The Supreme Court remanded the case back to the D.C. Circuit for further proceedings but left the rule in effect. The District is analyzing the impact, if any, of the court's ruling.

Provisions of the EPA's Regional Haze Rule require emissions controls known as Best Available Retrofit Technology (BART) for coal-fired power plants and other industrial facilities that emit air pollutants that reduce visibility in Class I areas, such as national parks. The District has financial interests in several coal-fired power plants that are subject to the BART requirements.

The EPA proposed a BART determination for NGS in January 2013. The District owns 21.7% of NGS. The EPA also invited the submittal of other alternative proposals that would achieve benefits equal to or greater than the EPA's proposal. In August 2013, the District and other interested parties reached an agreement on an alternative proposal (the NGS Proposal) that was then submitted to the EPA. Under the NGS Proposal, the total NOx emissions from 2009 to 2044 would be less than the emissions allowed by the EPA's proposal. The NGS Proposal included two alternatives. Alternative A would require ceasing coal generation on one unit or reducing generation by January 1, 2020, if certain ownership changes occur, and installing SCR or equivalent technology on two units by 2030. Alternative B would require achievement of NOx emission reductions equivalent to the shutdown of one unit between 2020 and 2030, and submittal of annual Implementation Plans describing the operating scenarios to be used to achieve greater NOx emissions reductions than the EPA's proposal. The EPA issued the final BART rule for NGS on August 8, 2014, adopting (with limited changes) the NGS Proposal as a better than BART determination. Four petitions for review of the final rule were filed before the Ninth Circuit by (i) The Hopi Tribe, (ii) National Parks Conservation Association, Sierra Club, Grand Canyon Trust and Natural Resources Defense Council, (iii) To' Nizhoni Ani, Black Mesa Water Coalition, and Diné Citizens Against Ruining the Environment (Diné CARE), and (iv) Vincent Yazzie. The District was granted intervention in all four appeals, as were three other intervenor parties. The four appeals were consolidated and a briefing schedule was established. The Ninth Circuit granted the Hopi Tribe and the EPA's joint motion to sever the Hopi Tribe's petition to allow the EPA and the Tribe to continue settlement discussions and set a separate briefing schedule. It is too soon to predict the outcome of this matter.

With respect to CGS, the District submitted a BART analysis to the ADEQ in 2008. The ADEQ completed its review of CGS and other BART-eligible sources and in 2011 sent a proposed Regional Haze State Implementation Plan (SIP) to the EPA that, among other things, accepted current controls at CGS as BART, subject to completion of pollution control equipment additions that were completed in 2014 pursuant to a consent decree. By letter dated November 17, 2011, the EPA indicated that it planned to develop a partial Regional Haze Federal Implementation Plan (FIP) for the State of Arizona, including potentially revisiting the BART determination for CGS to determine whether any additional pollution controls are warranted, such as the addition of SCR on the remaining unit. On December 5, 2012, the EPA finalized the FIP which imposes new emissions limits for PM, SO_2, and NOx under the BART provisions of the rule. The emissions limit for NOx will require installation of a second SCR system at CGS. The projected capital cost to the District of additional SCR at CGS is approximately $110 million. The District must meet the new limits by January 4, 2018. The District filed for judicial review of the final FIP with the U.S. Court of Appeals for the Ninth Circuit and filed an Administrative Petition for Reconsideration with the EPA. In April 2013, the EPA sent a letter to the District indicating it would grant the District's Petition for Reconsideration on a limited subset of the concerns listed in the petition. The EPA published a notice granting the petition in the Federal Register on March 31, 2015, and requested comments by May 15, 2015. Briefing on the merits in the Ninth Circuit is completed. The Ninth Circuit held oral argument on March 9, 2015, and has not yet ruled. Concurrently, the District has been engaged in discussions with the EPA to resolve this matter. It is too soon to predict the outcome of this matter.

On August 6, 2012, the EPA issued its final BART determination for Four Corners, which required the installation of SCRs on all five units, or the closure of Units 1, 2 and 3 and SCRs on Units 4 and 5. SCRs for Units 4 and 5 could cost $530.0 million, of which the District's share would be $53.0 million. On December 30, 2013, APS, on behalf of the Four Corners co-owners, notified the EPA that they had chosen the alternative BART compliance strategy requiring the permanent closure of Units 1, 2, and 3 by January 1, 2014, and installation and operation of SCRs on Units 4 and 5 by July 31, 2018.

The BART determinations for District-owned generating stations in Colorado were finalized on December 31, 2012. The final determination for Hayden Unit 2, in which the District owns 50%, requires installation of new emissions control equipment.

According to Xcel Energy, the operating agent for Hayden, installation of SCR on Hayden Unit 2 will cost approximately \$72.0 million, of which the District's share will be \$36.0 million. The new emission control equipment is required to be in service by July 2016. The final determinations for Craig Units 1 and 2, in which the District owns 29%, required installation of emissions control equipment estimated by the operating agent, Tri-State Generation and Transmission Association, Inc. (Tri-State), to cost approximately \$213.1 million, of which the District's share for the two units would be \$62.0 million, with necessary equipment to be in service by May 2017. In February and March 2013, two petitions for judicial review of the BART determination for Craig were filed by environmental organizations with the U.S. Court of Appeals for the Tenth Circuit. The Colorado Department of Public Health and Environment, Tri-State, PacifiCorp and Xcel Energy were granted intervention in one or both cases. On July 10, 2014, a motion was filed with the Court indicating that certain of the parties to the litigation had reached a settlement that, if approved, would further reduce NOx emission limits for Craig Unit 1 from .028 lb/MMBtu, on a 30-day rolling average, to .07 lb/MMBtu, calculated on a 30 boiler-operating-day rolling average, with a compliance deadline of August 31, 2021. No changes would be required for Craig Unit 2, which continues to have a compliance deadline of May 2017. The lawsuits are stayed pending the governmental approval and public notice process. PacifiCorp, one of the owners of Craig Unit 1 and an intervenor in the appeals, objected to the settlement, arguing that the settlement agreement is inappropriate, improper, inadequate, or inconsistent with the requirements of the CAA. On November 20, 2014, the Colorado Department of Public Health & Environment approved a revised Regional Haze Plan that adopts the settlement. The revised Regional Haze Plan was presented to and approved by the Colorado legislature during the spring 2015 legislative session. Tri-State is expecting EPA approval of the revised Regional Haze Plan by December 31, 2016. Depending on the final provisions of the EPA's Clean Power Plan rule, the installation of new emission control equipment for Craig Unit 1 would commence between August 2017 and August 2018. It is too soon to predict the outcome of this matter.

In May 2009, the National Parks Conservation Association (NPCA) and other environmental and tribal groups, petitioned the U.S. Department of the Interior–National Park Service (DOI) to certify to the EPA that visibility impairment in Grand Canyon National Park was "reasonably attributable" to oxides of nitrogen and particulate matter emissions from NGS (the NGS Petition). On February 16, 2010, NPCA and a similar coalition of environmental and tribal groups filed a similar petition with both the DOI and the U.S. Department of Agriculture – U.S. Forest Service (DOA) with respect to Four Corners, asking the DOI and the DOA to certify to the EPA that impairment of visibility in sixteen areas within 300 kilometers of Four Corners, including Grand Canyon National Park, among others, was reasonably attributable to pollutant emissions from Four Corners. However, the DOI and the DOA deferred action on the petitions pending completion of the BART determinations for the plants.

In 2009, the EPA contacted APS seeking detailed information regarding projects at, and operations of, Four Corners as a part of the EPA's national enforcement initiative under the new source review provisions of the CAA, and APS responded to the request. This EPA initiative is focused on determining whether companies had failed to disclose major repairs or alterations to facilities that, in the opinion of the EPA, would have required the installation of new pollution control equipment under the CAA. The EPA's pursuit of the initiative has resulted in the installation of expensive pollution control equipment at various facilities.

On October 4, 2011, following earlier notices of intent to sue, Earthjustice, representing Dine CARE, To' Nizhoni Ani, Sierra Club and National Parks Conservation Association, filed a citizen suit in the District Court of New Mexico against the co-owners of Four Corners, including the District, alleging violations of the prevention of significant deterioration (PSD) provisions of the CAA. The plaintiffs alleged that the defendants made two sets of major modifications to Units 4 and 5, which allowed the plant to significantly increase its emissions of pollutants without first obtaining a PSD permit. On January 13, 2012, the District was served with a First Amended Complaint asserting two additional claims related to Four Corners. In addition to the alleged PSD violations, the First Amended Complaint alleges violations of the New Source Performance Standards (NSPS) arising from the same two sets of modifications. Among other things, the plaintiffs ask the court to enjoin operations at Four Corners until the defendants apply for and obtain a PSD permit and comply with the NSPS, order the Four Corners owners to install best available control technology, and order civil penalties, including a beneficial mitigation project. The owners of Four Corners filed two motions to dismiss all of the claims in the First Amended Complaint and briefing has been completed but the decision on those motions was stayed to allow the parties time to pursue settlement. The parties subsequently reached agreement on a consent decree that provides for a civil penalty in the amount of $1.5 million and environmental mitigation projects in the total amount of $6.7 million, of which the District's collective share is approximately $498,400, and dismissal of the lawsuit. The consent decree was lodged with the court on June 24, 2015, and is subject to a 45-day public comment period.

In December 2009, the EPA found that emissions of GHG endanger public health and welfare. In April 2010, the EPA issued a "timing" rule that allows the EPA to regulate emissions of GHG by stationary sources such as power plants. Subsequently, the EPA released its "tailoring rule," which specifies thresholds that trigger permitting requirements for sources of GHG emissions. The rule applied to power plants beginning January 2, 2011. However, on June 30, 2014, the Supreme Court in *Utility Air Regulatory Group v. EPA*, rejected the EPA's tailoring rule. In March 2012, the EPA proposed a separate rule that would establish a single performance standard for CO_2 emissions from new power plants. These standards would apply to all newly constructed fossil-fuel-fired facilities. Under direction from the President, the EPA revised and re-proposed this rule on September 20, 2013, and subsequently published this proposed rule on January 8, 2014. The revised rule establishes separate CO_2 performance standards for coal-fired units and natural gas-fired units. For new units, these standards are based on the use of carbon capture and storage (CCS) for coal-fired utility boilers and integrated gasification combined cycle (IGCC) units, and the most efficient generating technology for natural gas-fired stationary combustion turbines. On June 2, 2014, the EPA issued proposed rules to establish performance standards to reduce CO_2 emissions from modified and reconstructed fossil-fuel-fired power plants. The proposed standards presume use of the most efficient generating technology available. The District submitted comments on October 16, 2014, on the proposal.

On June 2, 2014, the EPA issued a proposed rule that would establish enforceable guidelines for states to follow to reduce GHG emissions, specifically CO_2 emissions from existing fossil-fuel-fired electric generating units (EGUs). The proposal, entitled the "Clean Power Plan," would reduce CO_2 emissions from the U.S. electricity sector by 30% from 2005 levels by 2030. However, the EPA established different goals for each state depending on the state's generation mix. The EPA's proposed final goal for Arizona would require a 52% reduction in CO_2 emissions intensity by 2030 from the proposed program baseline year of 2012. The EPA's proposed interim goal for Arizona requires Arizona to achieve 90% of the total reductions required by the EPA as early as 2020, the first year of the 10-year interim period. In developing goals for Arizona, the EPA assumed that all of the in-state coal-fired generation would be replaced by natural gas and other generation by the year 2020. The District is actively engaged at the state, regional, and federal level to seek modifications to the rule as proposed. These efforts have focused primarily on the overall stringency of the reductions and the timing of the reductions. The District submitted comments to the EPA on the Clean Power Plan for existing EGUs on November 24, 2014. On November 4, 2014, the EPA published a supplemental proposal to the Clean Power Plan to address CO_2 emissions from EGUs located on tribal lands. The supplemental proposal uses the same analytical framework as the Clean Power Plan proposal for states that prescribes rate-based emission standards. The District submitted its comments on the proposed rule for EGUs located on tribal lands on December 19, 2014. The EPA plans to finalize the various Clean Power Plan rules in the summer of 2015. The District cannot predict the impact of these rules on its operations or finances at this time.

While the implications to the District will not be clear until final rules are released by the EPA, the District already has taken significant and material action to reduce its carbon emissions intensity. In 2004, the District Board directed management to enhance its resource portfolio by adding significant amounts of renewable energy and other sustainable resources through the development of the Sustainable Portfolio Plan (SPP). The SPP has matured and intensified over the years and the most recent revision to the SPP, approved by the District's Board in 2011, requires the District to meet 20% of its expected retail energy requirements with sustainable (zero carbon) resources by 2020. The District has already reduced system-wide carbon intensity by 18% from fiscal year 2006 through fiscal year 2012 and has been working to further enhance this performance. The current plan is to achieve an additional 34% reduction by fiscal year 2031 while managing the economic impact to customers and protecting grid reliability.

NATIONAL AMBIENT AIR QUALITY STANDARDS

Pursuant to the CAA, the EPA is required to review and, if appropriate and necessary, revise each of the established National Ambient Air Quality Standards (NAAQS) at five-year intervals. The current NAAQS for ozone, which was set at 75 parts per billion (ppb) on an 8-hour average in 2008, was required to be reviewed by the EPA no later than 2013. Because this schedule was not met, the EPA was sued by a number of environmental groups. Subsequently, a court order was issued requiring the EPA to issue a proposed rule based on review of the ozone NAAQS no later than December 1, 2014. The EPA issued a proposed rule to revise the ozone NAAQS on November 25, 2014. The proposal did not recommend a specific value for the new standard. Instead, the proposal indicated that the EPA was considering a revised ozone NAAQS in the range of 65 to 70 ppb on an 8-hour average for both the primary and secondary standards. The EPA also accepted comments on revising the ozone NAAQS to a value as low as 60 ppb or maintaining the current standard at 75 ppb. The EPA provided a 90-day comment period on the proposed rule and the District submitted its comments to the proposed rule on March 17, 2015.

The revised ozone NAAQS, if finalized in the currently proposed range, is expected to impact attainment designations in Arizona. Currently, Maricopa County and Pinal County are designated as "partial nonattainment" for the 2008 standard. Based on current monitoring data, it is expected that Arizona will have an expansion of its nonattainment areas if the ozone standard is lowered below 75 ppb. An expansion of Arizona's ozone nonattainment designations will have implications on the construction of new sources that emit NOx and VOCs – precursors to ozone formation – because the air permitting process in nonattainment areas is more stringent. After the effective date of the final designations (anticipated between October 2017 and October 2018), no permit may be issued for a new stationary source, or for a project at an existing stationary source in a nonattainment area, except in conformance with applicable Nonattainment New Source Review (NNSR) requirements. The District cannot predict the outcome of EPA's final rule or the impact of this rule on the District's operations or finances at this time.

The California Legislature has enacted various GHG laws. As a result, the Los Angeles Department of Water and Power (LADWP), one of the participants in NGS, and Southern California Edison Company (SCE), a participant in Four Corners Units 4 and 5, are precluded from extending their interests in the plants beyond a certain time period. As a result, SCE has sold its interest in Four Corners Units 4 and 5 to APS. In addition, El Paso Electric Co., on February 17, 2015, agreed to sell its 7% interest in Four Corners Units 4 and 5 to APS. LADWP, in turn, has agreed to sell its 21.2% interest in NGS to the District as described further in Note [14], SUBSEQUENT EVENTS.

In addition, legislation was passed at the Nevada legislature in June 2013 that requires NV Energy, another participant in NGS, to withdraw from the plant by the end of 2019. The District is still analyzing these actions and cannot predict the impact on its operations or finances at this time.

Solid and Hazardous Waste Management: In 2010, the EPA issued a proposed rule seeking comments on whether to regulate the handling and disposal of coal combustion residuals (CCRs), such as fly ash, bottom ash and flue gas desulfurization (FGD) sludge, as solid or hazardous waste. The District disposes of CCRs in dry landfill storage areas at CGS and NGS, with the exception of wet surface impoundment disposal of FGD sludge at CGS. Both CGS and NGS sell a portion of their fly ash for beneficial reuse as a constituent in concrete production. The District also owns interests in joint participation plants, such as Four Corners, Craig, Hayden and Springerville, which dispose of CCRs in dry storage areas and in wet surface impoundments. The EPA issued a final rule on December 19, 2014, that establishes federal criteria for management of CCRs as solid non-hazardous waste. The rule was published in the Federal Register on April 17, 2015, and will be effective on October 19, 2015. The rule generally requires any existing unlined CCR surface impoundment that is contaminating groundwater above a certain protection standard to stop receiving CCRs and either retrofit or close the impoundment, and further requires the closure of any CCR landfill or surface impoundment that cannot meet the applicable performance criteria for location restrictions or structural integrity. At this time, the District is analyzing the operations that would be covered by the rule and it is too early to estimate compliance costs. However, the District expects to incur additional costs in the future to comply with this new rule, which may include costs for new monitoring wells, compliance monitoring and the eventual closure of residual ponds and storage areas. As described in Note (2), SIGNIFICANT ACCOUNTING POLICIES, SRP has accrued an estimate of the costs related to the eventual closure of residual ponds and storage areas.

Endangered Species: Several species listed as threatened or endangered under the Endangered Species Act (ESA) have been discovered in and around reservoirs on the Salt and Verde rivers, as well as C.C. Cragin Reservoir, which is operated by SRP. Potential ESA issues also exist along the Little Colorado River in the vicinity of CGS and Springerville. The District obtained Incidental Take Permits (ITPs) from the United States Fish and Wildlife Service (USFWS), which allow full operation of Roosevelt Dam on the Salt River and of Horseshoe and Bartlett dams on the Verde River. The ITPs, and associated Habitat Conservation Plans (HCPs), identify the obligations, such as mitigation and wildlife monitoring, the District must undertake to comply with the ESA. The District has established trust funds to pay mitigation and monitoring expenses related to the implementation of both the Roosevelt HCP and Horseshoe-Bartlett HCP and believes it has recorded adequate reserves as a part of its environmental reserves to cover its related obligations. The District continues to assess the potential ESA liabilities and is working closely with the USFWS and other state and federal agencies to address potential species concerns as necessary, but cannot predict the ultimate outcome at this time.

On May 12, 2014, the USFWS and the National Marine Fisheries Service (Services) published two ESA rules and one draft policy document, each addressing the designation and protection of critical habitat. The proposed rules and policy increase the discretion of the Services to designate broad areas of occupied and unoccupied habitat as critical habitat. Once a critical habitat is designated, the ESA prohibits other federal agencies from engaging in actions that adversely modify critical habitat. The proposed rules and policy are considered to be among the most significant developments involving critical habitat designation in years. The District reviewed the proposed rules and policy to determine potential impacts to the District's HCPs, ongoing operations and new projects and developed comment letters addressing specific issues and concerns from both a water and power utility perspective. The public comment period for the proposed rules ended October 9, 2014. The District cannot predict the outcome at this time.

The USFWS is proceeding with listings for species that may be located in areas where the District has water and power utility operations. The USFWS has finalized the listing of Northern Mexican and Narrow-headed Gartersnakes and the western distinct population segment of the Yellow-billed cuckoo as threatened. Critical habitat for these species has been proposed and the District is awaiting the draft economic analysis and environmental assessment for the critical habitat proposals and is currently assessing the potential ESA liabilities from these recent listings.

The USFWS is expected to issue a proposed rule listing the roundtail chub and the Sonoran desert tortoise during the current federal fiscal year. These species are part of the Multi-District Litigation Settlement and, as such, the USFWS must make a decision to list the species or state that listing is not warranted. The District is currently assessing the potential ESA liabilities should these species be listed.

WATER RIGHTS

The District and the Association are parties to a state water-rights adjudication proceeding initiated in 1974 that encompasses the entire Gila River System (the Gila River Adjudication). This proceeding is pending in the Superior Court for the State of Arizona, Maricopa County, and will eventually result in the determination of all conflicting rights to water from the Gila River and its tributaries, including the Salt and Verde rivers. The District and the Association are unable to predict the ultimate outcome of this proceeding.

In 1978, a water-rights adjudication was initiated in the Apache County Superior Court for the State of Arizona with regard to the Little Colorado River System and will eventually result in the determination of all conflicting rights to water from the Little Colorado River and its tributaries, including Clear Creek, the location of C.C. Cragin Dam and Reservoir. The District is unable to predict the ultimate outcome of this proceeding, but believes an adequate water supply for CGS will remain available and that the rights to C.C. Cragin will be confirmed.

2015 PRICE PROCESS LITIGATION

On February 26, 2015, the District Board concluded a public process by approving changes and adjustments to its retail electric price plans, including an overall average annual price increase of 3.9%, to be phased in beginning with the April 2015 billing cycle. This overall increase was comprised of a 4.4 percent base increase and a 0.5 percent decrease to the Environmental Programs Cost Adjustment Factor.

In addition to other approved changes and adjustments, the Board approved a new price plan for residential customers who, after December 8, 2014, add solar or other technologies to generate some of their energy requirements (the E-27 Customer Generation Price Plan). SRP structured the new price plan for distributed generation customers to be in line with what non-distributed generation customers pay for the same services. The price plan includes a demand charge to better recover fixed costs related to the distributed generation customers' service facilities and their use of the grid, but also reduces the price such customers pay per kilowatt-hour for energy.

SolarCity Corporation, an active participant in the price process proceedings, filed a lawsuit against the District in Arizona Federal District Court on March 2, 2015, alleging, among other things, that the District, by its adoption of the Customer Generation Price Plan, acted unlawfully in an effort to preserve its existing monopoly over the retail provision of electric power for consumers and businesses. The suit asserts claims for unspecified damages and injunctive relief pursuant to federal antitrust laws, claims for injunctive relief under Arizona antitrust laws, and claims for injunctive relief based on Arizona law for intentional interference with prospective economic advantage and intentional interference with agreements between SolarCity and its prospective and current customers. On

May 20, 2015, SolarCity filed an amended complaint adding the Association as a defendant, alleging, among other things, that the District and the Association operate as alter egos. On June 23, 2015, the District and the Association each filed motions to dismiss raising federal and state immunities and seeking dismissal with prejudice of all claims asserted. While it is too soon to predict the outcome of this matter, both the District and the Association believe that the lawsuit is without merit and will aggressively defend the suit.

OTHER LITIGATION

In the normal course of business, SRP is exposed to various litigations or is a defendant in various litigation matters. In management's opinion, except as otherwise noted herein, the ultimate resolution of these matters will not have a material adverse effect on SRP's financial position or results of operations.

SELF-INSURANCE

SRP maintains various self-insurance retentions for certain casualty and property exposures. In addition, SRP has insurance coverage for amounts in excess of its self-insurance retention levels. SRP provides reserves based on management's best estimate of claims, including incurred but not reported claims. In management's opinion, the reserves established for these claims are adequate and any changes will not have a material adverse effect on SRP's financial position or results of operations. SRP records the reserves in deferred credits and other non-current liabilities in the accompanying Combined Balance Sheets.

[14] SUBSEQUENT EVENTS:

On May 14, 2015, the District's Board of Directors approved an agreement for the purchase of a 21.2 percent share of NGS, representing 477 megawatts of capacity owned by the Department of Water and Power for the City of Los Angeles ("LADWP"). At closing, the District will pay approximately $12.9 million to LADWP for its share. The agreement is subject to execution of the final agreement and obtaining the approval of the United States Bureau of Reclamation, among others. By its terms, the transaction will close no sooner than July 1, 2016, if all approvals have been obtained and conditions have been met.

See Note (7) LONG-TERM DEBT AND CAPITAL LEASE OBLIGATION and Note (8) COMMERCIAL PAPER AND CREDIT AGREEMENTS for information on issuance of revenue bonds and commercial paper subsequent to April 30, 2015.

INDEPENDENT AUDITOR'S REPORT

To the Board of Directors of the
Salt River Project Agricultural Improvement and
Power District and the Board of Governors of the
Salt River Valley Water Users' Association

We have audited the accompanying combined financial statements of Salt River Project Agricultural Improvement and Power District and its subsidiaries and the Salt River Valley Water Users' Association (collectively, "SRP"), which comprise the combined balance sheets as of April 30, 2015 and April 30, 2014, and the related combined statements of net revenues and cash flows for the years then ended.

Management's Responsibility for the Combined Financial Statements

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

Auditor's Responsibility

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

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the combined financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the combined financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to SRP's preparation and fair presentation of the combined financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of SRP's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the combined financial statements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the combined financial statements referred to above present fairly, in all material respects, the financial position of Salt River Project Agricultural Improvement and Power District and its subsidiaries and the Salt River Valley Water Users' Association at April 30, 2015 and April 30, 2014, and the results of their operations and their cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

PricewaterhouseCoopers LLP

July 17, 2015
PricewaterhouseCoopers LLP
Phoenix, Arizona

Delivering more than power.™

15-0547-01

Report of Independent Auditors and
Combined Financial Statements for

Southern California Public Power Authority

June 30, 2015 and 2014

MOSS-ADAMS LLP

Certified Public Accountants | Business Consultants

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REPORT OF INDEPENDENT AUDITORS

The Board of Directors and Participants of
Southern California Public Power Authority

Report on Financial Statements

We have audited the accompanying combined and individual projects' financial statements of Southern California Public Power Authority, which comprise the combined and individual projects' statements of net position as of June 30, 2015 and 2014, and the related combined and individual projects' statements of revenues, expenses and changes in net position, and cash flows for the years then ended, and the related notes to the financial statements.

Management's Responsibility for the Financial Statements

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

Auditor's Responsibility

Our responsibility is to express an opinion on these combined and individual projects' financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America and the California Code of Regulations, Title 2, Section 1131.2, State Controller's *Minimum Audit Requirements* for California Special Districts. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the combined and individual projects' financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the combined and individual projects' financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the combined and individual projects' financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the combined and individual projects' financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the combined and individual projects' financial statements.

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

REPORT OF INDEPENDENT AUDITORS (continued)

Opinions

In our opinion, the combined and individual projects' financial statements referred to above present fairly, in all material respects, the financial position of Southern California Public Power Authority and each of the Authority's projects: Palo Verde Project, San Juan Project, Magnolia Power Project, Canyon Power Project, Apex Power Project, Hoover Uprating Project, Tieton Hydropower Project, Milford I Wind Project, Milford II Wind Project, Windy Point Project, Linden Wind Energy Project, Southern Transmission System Project, Mead-Phoenix Project, Mead-Adelanto Project, Pinedale Project, Barnett Project, Prepaid Natural Gas Project, Ormat Geothermal Energy Project, MWD Small Hydro Project, Pebble Springs Project, Ameresco Chiquita Landfill Gas Project, Don A. Campbell Wild Rose Geothermal Project, Copper Mountain Solar 3 Project, Columbia Solar 2 Project, Project Development Fund, Projects' Stabilization Fund and SCPPA Fund as of June 30, 2015 and 2014, and the combined and individual results of the projects' operations and cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

Emphasis of Matter

As discussed in Note 2 to the financial statements, the Authority adopted the provisions of GASB 68, *Accounting and Financial Reporting for Pensions – an amendment of GASB Statement No. 27,* effective July 1, 2014. The beginning of year net position has been adjusted for this change. Our opinion is not modified with respect to this matter.

Other Matter

Required Supplementary Information

Accounting principles generally accepted in the United States of America require that the management's discussion and analysis, *Schedule of Proportionate Share of the Net Pension Liability as of June 30, 2015* and the *Schedule of Contributions as of June 30, 2015* be presented to supplement the financial statements. Such information, although not a part of the financial statements, is required by the Governmental Accounting Standards Board who considers it to be an essential part of financial reporting for placing the financial statements in an appropriate operational, economic, or historical context. We have applied certain limited procedures in the required supplementary information in accordance with auditing standards generally accepted in the United States of America, which consisted of inquiries of management about the methods of preparing the information and comparing the information for consistency with management's responses to our inquiries, the financial statements, and other knowledge we obtained during our audit of the financial statements. We do not express an opinion or provide any assurance on the information because the limited procedures do not provide us with sufficient evidence to express an opinion or provide any assurance.

Other Information

Our audit was conducted for the purpose of forming an opinion on the financial statements as a whole. The supplemental schedules of receipts and disbursements in funds for the year ended June 30, 2015, are presented for purposes of additional analysis and are not a required part of the basic financial statements. Such information has not been subjected to the auditing procedures applied in the audit of the basic financial statements, and accordingly, we do not express an opinion or provide any assurance on it.

Moss Adams LLP

Portland, Oregon
October 30, 2015

The following discussion and analysis of the financial performance of Southern California Public Power Authority (the Authority or SCPPA), provides an overview of the Authority's financial activities for the fiscal years ended June 30, 2015 and 2014. Please read this discussion and analysis in conjunction with the Authority's Combined Financial Statements, which begin on page 10. Description and other details pertaining to the Authority are included in the Notes to Combined Financial Statements.

The Authority is a joint powers authority whose primary purpose has been to provide joint financing and oversight for large joint projects for its member agencies that consist of eleven municipal electric utilities and one irrigation district in California. On a combined basis, these entities provide electricity to more than two million retail electric customers. A Board of Directors (the Board) governs the Authority, which consists of one representative from each member agency.

Using This Financial Report

This annual financial report consists of a series of financial statements and reflects the self-supporting activities of the Authority that are funded primarily through the sale of energy, natural gas, and transmission services to member agencies under project specific take-or-pay contracts that require each member agency to pay its proportionate share of operating and maintenance expenses and debt service with respect to such projects. The contracts cannot be terminated or amended in any manner that will impair or adversely affect the rights of the bondholders as long as any bonds issued by the specific project remain outstanding. The Authority also established take-and-pay contracts for the participants of the prepaid natural gas project where the payments received from the sale of gas will be sufficient to pay debt service. In addition, the Authority has entered into various power purchase agreements. These agreements are substantially take-and-pay contracts but there may be other costs not associated with the delivery of energy that the participants may be obligated to pay.

Combined Summary of Financial Condition and Changes in Net Position (in thousands)

	June 30, 2015	2014	2013
Assets			
Net utility plant	$ 1,475,962	$ 1,574,194	$ 1,362,772
Investments	676,135	679,569	730,573
Cash and cash equivalents	337,374	301,753	230,929
Prepaid and other	1,030,529	1,099,682	1,152,331
Total assets	3,520,000	3,655,198	3,476,605
Deferred outflows of resources	119,709	95,061	122,746
Total assets and deferred outflows of resources	$ 3,639,709	$ 3,750,259	$ 3,599,351
Liabilities			
Noncurrent liabilities	$ 3,249,181	$ 3,456,473	$ 3,307,841
Current liabilities	449,772	392,473	398,509
Total liabilities	3,698,953	3,848,946	3,706,350
Deferred inflows of resources	207	-	-
Net position			
Net investment in capital assets	(594,920)	(608,196)	(621,687)
Restricted	610,915	583,618	565,717
Unrestricted	(75,446)	(74,109)	(51,029)
Total net position	(59,451)	(98,687)	(106,999)
Total liabilities, deferred inflows of resources, and net position	$ 3,639,709	$ 3,750,259	$ 3,599,351
Revenues, expenses and changes in net position for the year ended June 30			
Operating revenues	$ 813,095	$ 702,327	$ 639,925
Operating expenses	(668,880)	(564,690)	(503,837)
Operating income	144,215	137,637	136,088
Investment and other income	21,909	30,066	14,727
Derivative gain (loss)	28,364	395	60,189
Debt expense	(157,254)	(156,729)	(157,645)
Change in net position	37,234	11,369	53,359
Net position, beginning of year, before adjustment	(98,687)	(106,999)	(176,987)
Less: Accumulated adjustment for change in accounting principal	(1,004)	-	-
Net position, beginning of year, as adjusted	(99,691)	(106,999)	(176,987)
Net contributions/(withdrawals) by participants	3,006	(3,057)	16,629
Net position, end of year	$ (59,451)	$ (98,687)	$ (106,999)

Combined Financial Statements (continued)

Net Position –

During fiscal year 2015 the Authority's net position increased by $40 million mainly due to the decrease in assets and deferred outflows of resources of $111 million offset by the decrease in liabilities of $151 million.

The decrease in the Authority's assets is due to the following:

- Utility Plant – decreased by $98 million.
  This decrease is primarily due to the $107 million scheduled depreciation in Generation and Transmission Projects; and $8 million depletion in Natural Gas Reserve Projects; offset by the $17 million ongoing capital improvements in the Palo Verde Project (PV), Apex Power Project (APP), and Magnolia Power Project (MPP).

- Investments – decreased by $3 million.
  This decrease is largely due to the $16 million release of reserves combined with the 2014A Revenue Bonds proceeds for the refunding of the San Juan Project (SJ) 2005A Revenue Bonds; $6 million release of Southern Transmission System (STS) reserves combined with the 2015A&B and 2015C Revenue Bond proceeds for the refunding of 2000A and 20008B Bonds. The decreases were offset by the $15 million accumulated overbillings in the APP; and $4 million participant's contribution and reinvestment of interest earnings in the Project Stabilization fund (PSF) and PV Decommissioning Trust Fund.

- Cash and cash equivalents – increased by $36 million.
  This increase is mainly due to the $32 million net of accumulated overbillings and advances in various Projects; $2 million Build America Bonds' (BABs) subsidy received in the Canyon Power Project (CPP) for the payment of debt service; and $6 million additional funds deposited in the Project Development funds (PDF) for the ongoing negotiations of the incoming Springbok Project and Clearwater Projects. The increases were offset by the release of $4 million reserve fund for the refunding of the 2005A Revenue Bonds in the SJ Project.

- Prepaid and other assets – decreased by $69 million.
  This decrease is primarily due to the $63 million amortizations of the prepaid assets in the Natural Gas Prepaid Project (NGPP), Milford 1, Milford II, and Windy Point/Windy Flats Project (Windy Point); and $6 million decrease in accounts receivable in various Projects.

Combined Financial Statements (continued)

- Deferred outflows of resources – increased by $24 million.
  The increase is largely due to the $28 million net increase of unamortized loss on refunding which is a result of the refunding of STS's 2000A and 2008B Revenue Bonds; and $8 million increase in the fair values of derivative instruments in the MPP and NGPP Projects; offset by the $12 million amortizations of loss on refunding in various debt-funded Projects.

Liabilities

The decrease in the Authority's liabilities of $151 million is primarily due to the following:

- $168 million of principal maturities and related amortizations for all debt-funded projects; $29 million net of the early retirement of debt in SJ; and $19 million net decrease in the reported change in fair value of the derivative instruments largely due to the termination of the STS 2000 Swaption. The decreases were offset by the $43 million bond premium received from the issuance of the STS 2015A&C Revenue Bonds; and $23 million increase in the accumulated overbillings, advances, and accruals in various Projects.

During fiscal year 2014, the Authority's assets and deferred outflow of resources increased by $151 million mainly due to the acquisition of the APP, and was offset by the $143 million increase in liabilities largely due to the issuance of the APP 2014 A&B Revenue Bonds to finance the acquisition, resulting in an increase in the Authority's net position of $8 million.

Operating income –

The net increase in operating income of $7 million is mainly due to the SJ Project which increased billings to the participants for early debt retirements, and received fire settlements totaling $13 million. The increase was offset by the $7 million decrease in billings in the STS due to the release of the unused bond proceeds of the 2008B Upgrade Funds for the debt service requirements.

During FY 2014, the net increase of $2 million is due to the $26 million increase in participants' billings for debt service requirements in the Mead-Adelanto (MA) and Mead-Phoenix (MP) Projects, and increased expenses for O&M costs and nuclear fuel in the MPP and PV Projects; and the receipt of $3 million in upfront savings for the restructuring of the Prepaid Project Bonds. This increase was offset by $28 million decrease in participants' billings in the SJ Project because of the completion of the scheduled major maintenance outages.

Combined Financial Statements (continued)

Investment and Other Income –

Investment and other income decreased $8 million primarily due to the receipt of a $5 million fire insurance settlement in SJ and $3 million upfront savings from the debt restructuring of the 2007 Gas Prepaid Project Bonds in FY 2014.

Derivative Gain (Loss) –

In June 2008, GASB issued Statement No 53, Accounting and Financial Reporting for Derivative Instruments, effective for financial statements for periods beginning after June 15, 2009. GASB 53 requires that the fair value of derivative instruments be reported in the financial statements as investment income or loss if the derivative fails to effectively hedge the risk of rising or falling cash flows or fair values. $28.4 million and $0.4 million were charged to expense and income related to the Authority's derivative instruments that were deemed investment instruments as of June 30, 2015 and 2014, respectively. The increase in derivative gain of $28 million is mainly due to termination of the STS 2000 Swaps. (See Note 5).

Debt Expense –

Debt expense increased by $1 million largely due to the $6 million increase in interest expense from the issuance of the APP 2014 A&B being in commercial operation for the entire fiscal year of 2015, as compared to three months in fiscal year 2014. The increase was offset by $2 million decrease in interest expense due to the refunding of SJ 2005 Revenue Bonds; and $3 million related to amortization for all debt-funded projects.

Financial outlook – The Authority's credit strength is based on a number of factors including:

- The collective credit strengths of each project participant;
- The low cost power the Projects provide the participants; and
- Strong legal provisions.

The Authority has take-or-pay power sales, natural gas sales, and transmission service contracts that unconditionally require the Participants to pay for the cost of operating and maintaining the Projects, including debt service, whether or not the Projects are operating or operable. Although the contracts have not been court-tested, a municipal utility's authority to enter into such contracts is rooted in the State's constitutional provisions for municipal electric utilities. The Participants of the Prepaid Natural Gas Project, however, are obligated only to purchase and pay for gas delivered by SCPPA at market-based prices in accordance with the prepaid gas sale agreements in take-and-pay contracts.

The Authority has also entered into various power purchase agreements that are substantially take-and-pay contracts but there may be other costs not associated with the delivery of energy that the participants may be obligated to pay.

Through the collaborative efforts of its members, the Authority has developed a comprehensive and dynamic strategic plan that provides a common vision for its members and a platform for joint action. SCPPA continues its involvement in legislative and regulatory affairs at both the state and federal levels to protect represented customers, by assuring resource adequacy, excellent reliability, and environmental stewardship. Backed by one of the strongest financial ratings in the utility industry, SCPPA maintains its traditional role of providing financing for its members' natural gas, generation, and transmission projects. In addition to the conventional areas of power, investments are also being made to provide customers with more renewable generation and energy efficiency.

AB 1890 required all California electric utilities to commit a portion of their revenue to other Public Benefit Programs, including energy efficiency, renewable energy, research, development and demonstration (RD&D), and low-income customer assistance. Since 1998, a combined $1.7 billion dollars have been spent by SCPPA members on their respective Public Benefits Programs to support local communities.

Renewable projects – Member agencies' electric utilities are governed by their respective city councils or other elected legislative bodies. Many of whom previously established voluntary targets including goals for the percentage of renewable energy they wish to obtain within their portfolios. Some have set targets as high as 40% by the year 2020. Many members are approaching, or have already exceeded their interim targets of 20% renewable energy and are now updating their objectives to meet 33% by 2020 as required by SBX1 2.

SCPPA continues to seek cost effective resources to support members' Renewable Portfolio Standard (RPS) objectives for 2016 and forward. SCPPA has an active working group focused on renewable energy development. This group, with representation from all twelve of the member agencies, has reviewed over five hundred (500) individual project proposals since starting in 2007. Many of these projects have advanced into specific contract negotiations, and over 1,000 MW of capacity are now being operated in support of members' renewable objectives.

Change in accounting principal – SCPPA adopted GASB Statement No. 68 (GASB 68) during fiscal year 2015. With the implementation of GASB 68, SCPPA's beginning net position has been adjusted to conform with the new reporting and accounting requirements. The statements established accounting and financial reporting standards for employers and public pension plans, including reporting of the net pension liability on the statement of net position, deferred inflows and deferred outflows associated with investment, economic and demographic gains and losses associated with the pension plans. GASB 68 also provides guidance related to the calculation of pension expense. The financial statements for fiscal year 2014 have not been restated as the necessary information to do so was not made available by the California Public Employees' Retirement System.

Summary

The management of the Authority is responsible for preparing the information in this management discussion and analysis, combined and individual projects' financial statements, and notes to combined financial statements. The financial statements were prepared according to accounting principles generally accepted in the United States of America, and they fairly portray the Authority's financial position and operating results. The notes to the financial statements are an integral part of the basic financial statements and provide additional financial information.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINED STATEMENTS OF NET POSITION
(AMOUNTS IN THOUSANDS)

	June 30, 2015	June 30, 2014
ASSETS		
Noncurrent assets		
Net utility plant	$ 1,475,962	$ 1,574,194
Investments – restricted	631,010	648,532
Investments – unrestricted	45,125	31,037
Advance to IPA - restricted	11,550	11,550
Advances for capacity and energy, net – restricted	2,036	3,688
Fair value of derivative instruments	2,229	752
Prepaid and other assets	909,230	968,744
Total noncurrent assets	3,077,142	3,238,497
Current assets		
Cash and cash equivalents – restricted	236,950	205,018
Cash and cash equivalents – unrestricted	100,424	96,735
Interest receivable	1,278	3,042
Accounts receivable	11,673	17,399
Materials and supplies	25,909	24,904
Prepaid and other assets	66,624	69,603
Total current assets	442,858	416,701
DEFERRED OUTFLOWS OF RESOURCES		
Unamortized loss on pension assets	353	-
Unamortized loss on refunding	96,202	79,668
Accumulated decrease in fair value of hedging derivatives	23,154	15,393
Total deferred outflows of resources	119,709	95,061
Total assets and deferred outflows of resources	$ 3,639,709	$ 3,750,259
LIABILITIES		
Noncurrent liabilities		
Long-term debt	$ 3,176,756	$ 3,353,692
Fair value of derivative instruments	36,857	55,984
Notes payable, net pension and other liabilities	9,118	15,890
Advances from participants	26,450	30,907
Total noncurrent liabilities	3,249,181	3,456,473
Current liabilities		
Debt due within one year	181,710	158,320
Notes payable and other liabilities due within one year	20,480	15,275
Advances from participants due within one year	45,634	50,892
Accrued interest	63,301	65,396
Accounts payable and accruals	133,067	96,337
Accrued property tax	5,580	6,253
Total current liabilities	449,772	392,473
Total liabilities	3,698,953	3,848,946
DEFERRED INFLOWS OF RESOURCES		
Unamortized gain on pension investments	207	-
Total deferred inflows of resources	207	-
NET POSITION		
Net investment in capital assets	(594,920)	(608,196)
Restricted	610,915	583,618
Unrestricted	(75,446)	(74,109)
Total net position	(59,451)	(98,687)
Total liabilities, deferred inflows of resources and net position	$ 3,639,709	$ 3,750,259

See accompanying notes.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINED STATEMENTS OF REVENUES, EXPENSES, AND CHANGES IN NET POSITION
(AMOUNTS IN THOUSANDS)

	Years Ended June 30, 2015	2014
Operating revenues		
Sales of electric energy	$ 628,515	$ 504,862
Sales of transmission services	140,541	151,086
Sales of natural gas	44,039	46,379
Total operating revenues	813,095	702,327
Operating expenses		
Operations and maintenance	537,216	445,016
Depreciation, depletion and amortization	106,590	97,964
Amortization of nuclear fuel	14,493	16,031
Decommissioning	10,857	5,679
Pension expense (credit)	(276)	-
Total operating expenses	668,880	564,690
Operating income	144,215	137,637
Non operating revenues (expenses)		
Investment and other income	21,909	30,066
Derivative gain	28,364	395
Debt expense	(157,254)	(156,729)
Net non operating revenues (expenses)	(106,981)	(126,268)
Change in net position	37,234	11,369
Net position – beginning of year, before adjustment	(98,687)	(106,999)
Less: Accumulated adjustment for change in accounting principal	(1,004)	-
Net position – beginning of year, as adjusted	(99,691)	(106,999)
Net contributions (distributions) by participants	3,006	(3,057)
Net position – end of year	$ (59,451)	$ (98,687)

See accompanying notes.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINED STATEMENTS OF CASH FLOWS
(AMOUNTS IN THOUSANDS)

	Years Ended June 30, 2015	2014
Cash flows from operating activities		
Receipts from participants	$ 700,656	$ 621,802
Receipts from sale of oil and gas	16,286	9,152
Payments to operating managers	(350,001)	(296,029)
Other disbursements and receipts	17,376	21,897
Net cash flows from operating activities	384,317	356,822
Cash flows from noncapital financing activities		
Advances by participants, net	1,590	25,708
Cash flows from capital financing activities		
Additions to plant and prepaid projects, net	(34,316)	(335,618)
Debt interest payments	(143,210)	(145,419)
Proceeds from sale of bonds	316,095	333,872
Payment for defeasance of revenue bonds	(349,670)	-
Transfer of funds from (to) Mine Reclamation Trust Fund	(420)	(489)
Transfer of funds from (to) other projects	-	(24,822)
Principal payments on debt	(122,520)	(189,730)
Payment for bond issue costs	(24,150)	(2,508)
Net cash used for capital and related financing activities	(358,191)	(364,714)
Cash flows from investing activities		
Interest received on investments	5,294	8,132
Purchases of investments	(425,834)	(436,386)
Proceeds from sale/maturity of investments	428,445	481,262
Net cash from investing activities	7,905	53,008
Net change in cash and cash equivalents	35,621	70,824
Cash and cash equivalents, beginning of year	301,753	230,929
Cash and cash equivalents, end of year	$ 337,374	$ 301,753
Reconciliation of operating income to net cash provided by operating activities		
Operating income	$ 144,215	$ 137,637
Adjustments to reconcile operating income to net cash provided		
Depreciation, depletion and amortization	158,745	149,779
Decommissioning	10,857	5,679
Advances for capacity and energy	2,550	3,031
Amortization of nuclear fuel	14,493	16,031
Pension expense	(276)	-
Changes in assets and liabilities		
Accounts receivable	4,481	(4,830)
Accounts payable and accruals	33,764	29,294
Other	15,488	20,201
Net cash provided by operating activities	$ 384,317	$ 356,822
Cash and cash equivalents as stated in the Combined Statements of Net Position		
Cash and cash equivalents – restricted	$ 236,950	$ 205,018
Cash and cash equivalents – unrestricted	100,424	96,735
	$ 337,374	$ 301,753

See accompanying notes.

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SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINING STATEMENTS OF NET POSITION
JUNE 30, 2015
(AMOUNTS IN THOUSANDS)

	GENERATION				
	Palo Verde	San Juan	Magnolia Power	Canyon Power	Apex Power
ASSETS					
Noncurrent assets					
Net utility plant	$ 60,006	$ 64,103	$ 209,944	$ 248,624	$ 279,522
Investments – restricted	189,229	11,975	52,576	22,718	37,981
Investments – unrestricted	23,742	-	-	-	-
Advance to IPA – restricted	-	-	-	-	-
Advances for capacity and energy, net – restricted	-	-	-	-	-
Fair value of derivative instruments	-	-	-	-	-
Prepaid and other assets	-	739	-	-	-
Total noncurrent assets	272,977	76,817	262,520	271,342	317,503
Current assets					
Cash and cash equivalents – restricted	22,159	15,075	29,108	11,299	16,667
Cash and cash equivalents – unrestricted	11,616	5,913	7,930	650	17,440
Interest receivable	487	20	246	46	3
Accounts receivable	2,226	376	355	87	-
Materials and supplies	10,326	4,880	7,146	1,091	2,466
Prepaid and other assets	737	1,434	1,306	44	741
Total current assets	47,551	27,698	46,091	13,217	37,317
DEFERRED OUTFLOWS OF RESOURCES					
Unamortized loss on refunding	-	74	11,687	-	-
Accumulated decrease in fair value of hedging derivatives	-	-	13,272	-	-
Total deferred outflows of resources	-	74	24,959	-	-
Total assets and deferred outflows of resources	$ 320,528	$ 104,589	$ 333,570	$ 284,559	$ 354,820
LIABILITIES					
Noncurrent liabilities					
Long-term debt	$ 24,440	$ 21,345	$ 319,423	$ 307,987	$ 323,602
Fair value of derivative instruments	-	-	26,975	-	-
Notes payable and other liabilities	7,024	-	-	-	-
Advances from participants	-	-	-	-	-
Total noncurrent liabilities	31,464	21,345	346,398	307,987	323,602
Current liabilities					
Debt due within one year	11,690	21,590	10,985	-	9,335
Notes payable and other liabilities due within one year	6,700	-	13,152	-	-
Advances from participants due within one year	-	9,332	17,796	2,225	-
Accrued interest	3	181	3,599	8,366	6,305
Accounts payable and accruals	21,629	5,409	5,330	422	23,434
Accrued property tax	1,650	372	-	-	-
Total current liabilities	41,672	36,884	50,862	11,013	39,074
Total liabilities	73,136	58,229	397,260	319,000	362,676
NET POSITION					
Net investment in capital assets	23,876	15,399	(108,777)	(55,124)	(22,315)
Restricted	185,497	24,139	55,914	19,233	18,490
Unrestricted	38,019	6,822	(10,827)	1,450	(4,031)
Total net position	247,392	46,360	(63,690)	(34,441)	(7,856)
Total liabilities and net position	$ 320,528	$ 104,589	$ 333,570	$ 284,559	$ 354,820

See accompanying notes.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINING STATEMENTS OF NET POSITION
JUNE 30, 2014
(AMOUNTS IN THOUSANDS)

	GENERATION				
	Palo Verde	San Juan	Magnolia Power	Canyon Power	Apex Power
ASSETS					
Noncurrent assets					
Net utility plant	$ 72,982	$ 75,461	$ 219,668	$ 258,135	$ 290,782
Investments - restricted	194,156	21,213	55,558	23,297	23,477
Investments - unrestricted	30,477	-	-	-	-
Advance to IPA - restricted	-	-	-	-	-
Advances for capacity and energy, net - restricted	-	-	-	-	-
Fair value of derivative instruments	-	-	-	-	-
Prepaid and other assets	-	727	-	-	-
Total noncurrent assets	297,615	97,401	275,226	281,432	314,259
Current assets					
Cash and cash equivalents - restricted	9,869	8,596	27,618	7,576	16,306
Cash and cash equivalents - unrestricted	7,423	13,732	6,127	1,697	17,430
Interest receivable	538	25	116	1,864	16
Accounts receivable	5,332	177	1,621	59	-
Due from other project - restricted	-	-	-	-	-
Materials and supplies	9,826	4,563	7,021	1,042	2,452
Prepaid and other assets	677	1,428	822	-	812
Total current assets	33,665	28,521	43,325	12,238	37,016
DEFERRED OUTFLOWS OF RESOURCES					
Unamortized loss on refunding	-	1,000	12,899	-	-
Accumulated decrease in fair value of hedging derivatives	-	-	6,856	-	-
Total deferred outflows of resources	-	1,000	19,755	-	-
Total assets and deferred outflows of resources	$ 331,280	$ 126,922	$ 338,306	$ 293,670	$ 351,275
LIABILITIES					
Noncurrent liabilities					
Long-term debt	$ 36,130	$ 60,161	$ 331,564	$ 309,045	$ 333,684
Fair value of derivative instruments	-	-	19,419	-	-
Notes payable and other liabilities	13,413	-	-	-	-
Advances from participants	-	-	-	-	2,500
Total noncurrent liabilities	49,543	60,161	350,983	309,045	336,184
Current liabilities					
Debt due within one year	11,330	13,200	10,565	-	-
Notes payable and other liabilities due within one year	6,653	-	8,622	-	-
Advances from participants due within one year	-	9,082	22,429	2,225	-
Accrued interest	1	1,797	3,639	8,366	3,327
Accounts payable and accruals	12,615	10,448	6,141	196	17,073
Accrued property tax	1,303	371	-	-	-
Due to other projects	-	-	-	-	-
Total current liabilities	31,902	34,898	51,396	10,787	20,400
Total liabilities	81,445	95,059	402,379	319,832	356,584
NET POSITION					
Net investment in capital assets	25,522	245	(109,533)	(46,548)	(11,985)
Restricted	183,786	22,536	57,196	17,785	3,054
Unrestricted	40,527	9,082	(11,736)	2,601	3,622
Total net position	249,835	31,863	(64,073)	(26,162)	(5,309)
Total liabilities and net position	$ 331,280	$ 126,922	$ 338,306	$ 293,670	$ 351,275

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINING STATEMENTS OF NET POSITION
JUNE 30, 2015
(AMOUNTS IN THOUSANDS)

	GREEN POWER					
	Hoover Uprating	Tieton Hydropower	Milford I Wind	Milford II Wind	Windy Point Project	Linden Wind
ASSETS						
Noncurrent assets						
Net utility plant	$ -	$ 39,752	$ -	$ -	$ -	$ 118,656
Investments – restricted	3,136	4,956	26,267	3,249	21,293	2,303
Investments – unrestricted	560	-	2,502	2,823	3,003	1,501
Advance to IPA – restricted	-	-	-	-	-	-
Advances for capacity and energy, net – restricted	2,036	-	-	-	-	-
Fair value of derivative instruments	-	-	-	-	-	-
Prepaid and other assets	-		152,534	131,890	389,492	-
Total noncurrent assets	5,732	44,708	181,303	137,962	413,788	122,460
Current assets						
Cash and cash equivalents – restricted	89	2,554	11,855	9,199	19,228	7,988
Cash and cash equivalents – unrestricted	792	579	1,944	2,403	5,977	223
Interest receivable	1	13	56	14	51	-
Accounts receivable	-	-	-	-	-	129
Materials and supplies	-	-	-	-	-	-
Prepaid and other assets	1,667	408	11,410	8,706	27,962	10
Total current assets	2,549	3,554	25,265	20,322	53,218	8,350
DEFERRED OUTFLOWS OF RESOURCES						
Unamortized loss on refunding	-	-	-	-	-	-
Accumulated decrease in fair value of hedging derivatives	-	-	-	-	-	-
Total deferred outflows of resources	-	-	-	-	-	-
Total assets and deferred outflows of resources	$ 8,281	$ 48,262	$ 206,568	$ 158,284	$ 467,006	$ 130,810
LIABILITIES						
Noncurrent liabilities						
Long-term debt	$ 4,181	$ 49,931	$ 204,704	$ 149,610	$ 463,114	$ 127,753
Fair value of derivative instruments	-	-	-	-	-	-
Notes payable and other liabilities	-	-	-	-	-	-
Advances from participants	-	-	-	-	-	-
Total noncurrent liabilities	4,181	49,931	204,704	149,610	463,114	127,753
Current liabilities						
Debt due within one year	1,930	840	8,820	5,530	19,390	3,670
Notes payable and other liabilities due within one year	-	-	-	-	-	-
Advances from participants due within one year	-	202	250	250	1,000	2,004
Accrued interest	80	1,259	5,025	3,665	10,828	3,242
Accounts payable and accruals	121	640	4,165	4,961	7,452	759
Accrued property tax	-	-	-	-	727	258
Total current liabilities	2,131	2,941	18,260	14,406	39,397	9,933
Total liabilities	6,312	52,872	222,964	164,016	502,511	137,686
NET POSITION						
Net investment in capital assets	-	(11,019)	-	-	-	(12,767)
Restricted	723	6,264	-	-	-	7,182
Unrestricted	1,246	145	(16,396)	(5,732)	(35,505)	(1,291)
Total net position	1,969	(4,610)	(16,396)	(5,732)	(35,505)	(6,876)
Total liabilities and net position	$ 8,281	$ 48,262	$ 206,568	$ 158,284	$ 467,006	$ 130,810

See accompanying notes.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINING STATEMENTS OF NET POSITION
JUNE 30, 2014
(AMOUNTS IN THOUSANDS)

	GREEN POWER					
	Hoover Uprating	Tieton Hydropower	Milford I Wind	Milford II Wind	Windy Point Project	Linden Wind Energy
ASSETS						
Noncurrent assets						
Net utility plant	$ -	$ 41,205	$ -	$ -	$ -	$ 124,470
Investments - restricted	2,982	5,383	31,219	6,973	22,812	4,674
Investments - unrestricted	560	-	-	-	-	-
Advance to IPA - restricted	-	-	-	-	-	-
Advances for capacity and energy, net - restricted	3,688	-	-	-	-	-
Fair value of derivative instruments	-	-	-	-	-	-
Prepaid and other assets	-	-	163,935	140,588	416,944	-
Total noncurrent assets	7,230	46,588	195,154	147,561	439,756	129,144
Current assets						
Cash and cash equivalents - restricted	181	2,124	6,475	5,372	17,307	4,772
Cash and cash equivalents - unrestricted	787	684	8,723	5,932	7,575	2,534
Interest receivable	2	14	56	14	16	1
Accounts receivable	-	-	-	-	-	400
Due from other project - restricted	-	-	-	-	-	-
Materials and supplies	-	-	-	-	-	-
Prepaid and other assets	1,572	-	11,401	8,697	32,241	-
Total current assets	2,542	2,822	26,655	20,015	57,139	7,707
DEFERRED OUTFLOWS OF RESOURCES						
Unamortized loss on refunding	-	-	-	-	-	-
Accumulated decrease in fair value of hedging derivatives	-	-	-	-	-	-
Total deferred outflows of resources	-	-	-	-	-	-
Total assets and deferred outflows of resources	$ 9,772	$ 49,410	$ 221,809	$ 167,576	$ 496,895	$ 136,851
LIABILITIES						
Noncurrent liabilities						
Long-term debt	$ 6,127	$ 50,836	$ 214,773	$ 157,200	$ 488,305	$ 132,382
Fair value of derivative instruments	-	-	-	-	-	-
Notes payable and other liabilities	-	-	-	-	-	-
Advances from participants	-	-	-	-	-	-
Total noncurrent liabilities	6,127	50,836	214,773	157,200	488,305	132,382
Current liabilities						
Debt due within one year	1,835	815	8,450	5,270	18,535	3,530
Notes payable and other liabilities due within one year	-	-	-	-	-	-
Advances from participants due within one year	-	202	250	250	1,000	2,004
Accrued interest	104	1,273	5,211	3,797	11,253	3,313
Accounts payable and accruals	65	416	8,432	5,657	6,370	1,093
Accrued property tax	-	-	-	-	737	247
Due to other projects	-	-	-	-	-	-
Total current liabilities	2,004	2,706	22,343	14,974	37,895	10,187
Total liabilities	8,131	53,542	237,116	172,174	526,200	142,569
NET POSITION						
Net investment in capital assets	-	(10,446)	-	-	-	(11,443)
Restricted	357	6,249	-	-	-	6,534
Unrestricted	1,284	65	(15,307)	(4,598)	(29,305)	(809)
Total net position	1,641	(4,132)	(15,307)	(4,598)	(29,305)	(5,718)
Total liabilities and net position	$ 9,772	$ 49,410	$ 221,809	$ 167,576	$ 496,895	$ 136,851

See accompanying notes.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINING STATEMENTS OF NET POSITION
JUNE 30, 2015
(AMOUNTS IN THOUSANDS)

	TRANSMISSION		
	Southern Transmission System	Mead- Phoenix	Mead- Adelanto
ASSETS			
Noncurrent assets			
Net utility plant	$ 239,013	$ 30,006	$ 86,741
Investments – restricted	48,904	2,900	14,397
Investments – unrestricted	-	-	-
Advance to IPA – restricted	11,550	-	-
Advances for capacity and energy, net – restricted	-	-	-
Fair value of derivative instruments	-		2,229
Prepaid and other assets	-	-	-
Total noncurrent assets	299,467	32,906	103,367
Current assets			
Cash and cash equivalents – restricted	40,466	2,358	12,098
Cash and cash equivalents – unrestricted	4,983	2,319	2,062
Interest receivable	22	-	1
Accounts receivable	4,438	-	48
Materials and supplies	-	-	-
Prepaid and other assets	20	123	12
Total current assets	49,929	4,800	14,221
DEFERRED OUTFLOWS OF RESOURCES			
Unamortized loss on refunding	78,315	1,586	4,540
Accumulated decrease in fair value of hedging derivatives	-	-	-
Total deferred outflows of resources	78,315	1,586	4,540
Total assets and deferred outflows of resources	$ 427,711	$ 39,292	$ 122,128
LIABILITIES			
Noncurrent liabilities			
Long-term debt	$ 667,654	$ 29,730	$ 99,570
Fair value of derivative instruments	-	-	-
Notes payable and other liabilities	-	-	1,220
Advances from participants	-	-	-
Total noncurrent liabilities	667,654	29,730	100,790
Current liabilities			
Debt due within one year	53,085	5,480	17,690
Notes payable and other liabilities due within one year	-	-	628
Advances from participants due within one year	-	-	-
Accrued interest	12,565	693	2,537
Accounts payable and accruals	12,901	752	688
Accrued property tax	-	-	-
Total current liabilities	78,551	6,925	21,543
Total liabilities	746,205	36,655	122,333
NET POSITION			
Net investment in capital assets	(407,143)	(6,105)	(27,828)
Restricted	92,114	5,556	23,688
Unrestricted	(3,465)	3,186	3,935
Total net position	(318,494)	2,637	(205)
Total liabilities and net position	$ 427,711	$ 39,292	$ 122,128

See accompanying notes.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINING STATEMENTS OF NET POSITION
JUNE 30, 2014
(AMOUNTS IN THOUSANDS)

	TRANSMISSION		
	Southern Transmission System	Mead- Phoenix	Mead- Adelanto
ASSETS			
Noncurrent assets			
Net utility plant	$ 261,767	$ 31,287	$ 91,226
Investments - restricted	66,092	2,300	17,900
Investments - unrestricted	-	-	-
Advance to IPA - restricted	11,550	-	-
Advances for capacity and energy, net - restricted	-	-	-
Fair value of derivative instruments	-	-	752
Prepaid and other assets	-	-	-
Total noncurrent assets	339,409	33,587	109,878
Current assets			
Cash and cash equivalents - restricted	32,585	4,100	10,050
Cash and cash equivalents - unrestricted	146	322	358
Interest receivable	54	1	1
Accounts receivable	3,834	114	63
Due from other project - restricted	-	-	-
Materials and supplies	-	-	-
Prepaid and other assets	-	-	-
Total current assets	36,619	4,537	10,472
DEFERRED OUTFLOWS OF RESOURCES			
Unamortized loss on refunding	50,438	3,751	11,580
Accumulated decrease in fair value of hedging derivatives	-	-	-
Total deferred outflows of resources	50,438	3,751	11,580
Total assets and deferred outflows of resources	$ 426,466	$ 41,875	$ 131,930
LIABILITIES			
Noncurrent liabilities			
Long-term debt	$ 681,723	$ 35,928	$ 120,185
Fair value of derivative instruments	28,028	-	-
Notes payable and other liabilities	-	-	2,477
Advances from participants	-	-	-
Total noncurrent liabilities	709,751	35,928	122,662
Current liabilities			
Debt due within one year	50,885	5,215	17,385
Notes payable and other liabilities due within one year	-	-	-
Advances from participants due within one year	-	-	-
Accrued interest	14,391	814	2,954
Accounts payable and accruals	6,035	102	363
Accrued property tax	-	-	-
Due to other projects	-	-	-
Total current liabilities	71,311	6,131	20,702
Total liabilities	781,062	42,059	143,364
NET POSITION			
Net investment in capital assets	(412,196)	(6,105)	(37,241)
Restricted	87,683	5,556	24,970
Unrestricted	(30,083)	365	837
Total net position	(354,596)	(184)	(11,434)
Total liabilities and net position	$ 426,466	$ 41,875	$ 131,930

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINING STATEMENTS OF NET POSITION
JUNE 30, 2015
(AMOUNTS IN THOUSANDS)

	NATURAL GAS		
	Pinedale	Barnett	Prepaid Natural Gas
ASSETS			
Noncurrent assets			
Net utility plant	$ 44,625	$ 50,710	$ -
Investments - restricted	-	31,187	11,586
Investments - unrestricted	-	-	-
Advance to IPA - restricted	-	-	-
Advances for capacity and energy, net - restricted	-	-	-
Fair value of derivative instruments	-	-	-
Prepaid and other assets	126	-	234,449
Total noncurrent assets	44,751	81,897	246,035
Current assets			
Cash and cash equivalents - restricted	4,607	11,117	4,399
Cash and cash equivalents - unrestricted	4,696	1,264	77
Interest receivable	-	48	55
Accounts receivable	1,497	626	1,459
Materials and supplies	-	-	-
Prepaid and other assets	679	10	11,335
Total current assets	11,479	13,065	17,325
DEFERRED OUTFLOWS OF RESOURCES			
Unamortized loss on refunding	-	-	-
Accumulated decrease in fair value of hedging derivatives	-	-	9,882
Total deferred outflows of resources	-	-	9,882
Total assets and deferred outflows of resources	$ 56,230	$ 94,962	$ 273,242
LIABILITIES			
Noncurrent liabilities			
Long-term debt	$ 22,489	$ 52,836	$ 308,387
Fair value of derivative instruments	-	-	9,882
Notes payable and other liabilities	-	-	-
Advances from participants	17,898	8,552	-
Total noncurrent liabilities	40,387	61,388	318,269
Current liabilities			
Debt due within one year	2,274	5,326	4,075
Notes payable and other liabilities due within one year	-	-	-
Advances from participants due within one year	1,964	1,218	-
Accrued interest	694	1,632	2,627
Accounts payable and accruals	3,478	2,304	347
Accrued property tax	2,573	-	-
Total current liabilities	10,983	10,480	7,049
Total liabilities	51,370	71,868	325,318
NET POSITION			
Net investment in capital assets	205	12,419	-
Restricted	4,494	11,034	-
Unrestricted	161	(359)	(52,076)
Total net position	4,860	23,094	(52,076)
Total liabilities and net position	$ 56,230	$ 94,962	$ 273,242

See accompanying notes.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINING STATEMENTS OF NET POSITION
JUNE 30, 2014
(AMOUNTS IN THOUSANDS)

	NATURAL GAS		
	Pinedale	Barnett	Prepaid Natural Gas
ASSETS			
Noncurrent assets			
Net utility plant	$ 48,747	$ 54,240	$ -
Investments - restricted	-	27,950	11,579
Investments - unrestricted	-	-	-
Advance to IPA - restricted	-	-	-
Advances for capacity and energy, net - restricted	-	-	-
Fair value of derivative instruments	-	-	-
Prepaid and other assets	126	-	246,424
Total noncurrent assets	48,873	82,190	258,003
Current assets			
Cash and cash equivalents - restricted	10,055	13,988	6,839
Cash and cash equivalents - unrestricted	9,235	2,121	23
Interest receivable	-	43	47
Accounts receivable	1,711	1,562	1,441
Due from other project - restricted	-	-	-
Materials and supplies	-	-	-
Prepaid and other assets	652	-	11,292
Total current assets	21,653	17,714	19,642
DEFERRED OUTFLOWS OF RESOURCES			
Unamortized loss on refunding	-	-	-
Accumulated decrease in fair value of hedging derivatives	-	-	8,537
Total deferred outflows of resources	-	-	8,537
Total assets and deferred outflows of resources	$ 70,526	$ 99,904	$ 286,182
LIABILITIES			
Noncurrent liabilities			
Long-term debt	$ 24,763	$ 58,162	$ 312,724
Fair value of derivative instruments	-	-	8,537
Notes payable and other liabilities	-	-	-
Advances from participants	19,261	9,146	-
Total noncurrent liabilities	44,024	67,308	321,261
Current liabilities			
Debt due within one year	2,219	5,211	3,875
Notes payable and other liabilities due within one year	-	-	-
Advances from participants due within one year	10,045	1,301	-
Accrued interest	745	1,752	2,659
Accounts payable and accruals	4,853	2,426	2,796
Accrued property tax	3,595	-	-
Due to other projects	-	-	-
Total current liabilities	21,457	10,690	9,330
Total liabilities	65,481	77,998	330,591
NET POSITION			
Net investment in capital assets	341	6,970	-
Restricted	2,206	13,679	-
Unrestricted	2,498	1,257	(44,409)
Total net position	5,045	21,906	(44,409)
Total liabilities and net position	$ 70,526	$ 99,904	$ 286,182

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINING STATEMENTS OF NET POSITION
JUNE 30, 2015
(AMOUNTS IN THOUSANDS)

	POWER PURCHASE AGREEMENTS						
	Ormat Geothermal Energy	MWD Small Hydro	Pebble Springs	Ameresco Chiquita Landfill Gas	Don A. Campbell Wild Rose Geothermal	Copper Mountain Solar 3	Columbia Solar 2
ASSETS							
Noncurrent assets							
Net utility plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Investments - restricted	-	-	-	-	-	-	-
Investments - unrestricted	-	-	1,000	-	-	9,994	-
Advance to IPA - restricted	-	-	-	-	-	-	-
Advances for capacity and energy, net - restricted	-	-	-	-	-	-	-
Fair value of derivative instruments	-	-	-	-	-	-	-
Prepaid and other assets	-	-	-	-	-	-	-
Total noncurrent assets	-	-	1,000	-	-	9,994	-
Current assets							
Cash and cash equivalents - restricted	1	1	-	1	6	6	-
Cash and cash equivalents - unrestricted	1,816	1,338	2,761	1,417	3,363	16,976	1,885
Interest receivable	-	-	-	-	-	-	-
Accounts receivable	140	255	-	-	-	-	37
Materials and supplies	-	-	-	-	-	-	-
Prepaid and other assets	1	1	6	1	6	5	-
Total current assets	1,958	1,595	2,767	1,419	3,375	16,987	1,922
DEFERRED OUTFLOWS OF RESOURCES							
Unamortized loss on refunding	-	-	-	-	-	-	-
Accumulated decrease in fair value of hedging derivatives	-	-	-	-	-	-	-
Total deferred outflows of resources	-	-	-	-	-	-	-
Total assets and deferred outflows of resources	$ 1,958	$ 1,595	$ 3,767	$ 1,419	$ 3,375	$ 26,981	$ 1,922
LIABILITIES							
Noncurrent liabilities							
Long-term debt	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Fair value of derivative instruments	-	-	-	-	-	-	-
Notes payable and other liabilities	-	-	-	-	-	-	-
Advances from participants	-	-	-	-	-	-	-
Total noncurrent liabilities	-	-	-	-	-	-	-
Current liabilities							
Debt due within one year	-	-	-	-	-	-	-
Notes payable and other liabilities due within one year	-	-	-	-	-	-	-
Advances from participants due within one year	857	500	-	400	480	-	538
Accrued interest	-	-	-	-	-	-	-
Accounts payable and accruals	1,101	1,095	3,767	1,019	2,895	26,981	1,384
Accrued property tax	-	-	-	-	-	-	-
Total current liabilities	1,958	1,595	3,767	1,419	3,375	26,981	1,922
Total liabilities	1,958	1,595	3,767	1,419	3,375	26,981	1,922
NET POSITION							
Net investment in capital assets	-	-	-	-	-	-	-
Restricted	-	-	-	-	-	-	-
Unrestricted	-	-	-	-	-	-	-
Total net position	-	-	-	-	-	-	-
Total liabilities and net position	$ 1,958	$ 1,595	$ 3,767	$ 1,419	$ 3,375	$ 26,981	$ 1,922

See accompanying notes.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINING STATEMENTS OF NET POSITION
JUNE 30, 2014
(AMOUNTS IN THOUSANDS)

	POWER PURCHASE AGREEMENTS					
	Ormat Geothermal Energy	MWD Small Hydro	Pebble Springs	Ameresco Chiquita Landfill Gas	Don A. Campbell Wild Rose Geothermal	Copper Mountain Solar 3
ASSETS						
Noncurrent assets						
Net utility plant	$ -	$ -	$ -	$ -	$ -	$ -
Investments - restricted	-	-	-	-	-	-
Investments - unrestricted	-	-	-	-	-	-
Advance to IPA - restricted	-	-	-	-	-	-
Advances for capacity and energy, net - restricted	-	-	-	-	-	-
Fair value of derivative instruments	-	-	-	-	-	-
Prepaid and other assets	-	-	-	-	-	-
Total noncurrent assets	-	-	-	-	-	-
Current assets						
Cash and cash equivalents - restricted	-	-	-	-	-	-
Cash and cash equivalents - unrestricted	2,819	1,221	4,123	2,041	67	1,615
Interest receivable	-	-	-	-	-	-
Accounts receivable	-	170	-	-	915	-
Due from other project - restricted	-	-	-	-	-	-
Materials and supplies	-	-	-	-	-	-
Prepaid and other assets	3	6	-	-	-	-
Total current assets	2,822	1,397	4,123	2,041	982	1,615
DEFERRED OUTFLOWS OF RESOURCES						
Unamortized loss on refunding	-	-	-	-	-	-
Accumulated decrease in fair value of hedging derivatives	-	-	-	-	-	-
Total deferred outflows of resources	-	-	-	-	-	-
Total assets and deferred outflows of resources	$ 2,822	$ 1,397	$ 4,123	$ 2,041	$ 982	$ 1,615
LIABILITIES						
Noncurrent liabilities						
Long-term debt	$ -	$ -	$ -	$ -	$ -	$ -
Fair value of derivative instruments	-	-	-	-	-	-
Notes payable and other liabilities	-	-	-	-	-	-
Advances from participants	-	-	-	-	-	-
Total noncurrent liabilities	-	-	-	-	-	-
Current liabilities						
Debt due within one year	-	-	-	-	-	-
Notes payable and other liabilities due within one year	-	-	-	-	-	-
Advances from participants due within one year	857	500	-	400	-	-
Accrued interest	-	-	-	-	-	-
Accounts payable and accruals	1,965	897	4,123	1,641	982	1,615
Accrued property tax	-	-	-	-	-	-
Due to other projects	-	-	-	-	-	-
Total current liabilities	2,822	1,397	4,123	2,041	982	1,615
Total liabilities	2,822	1,397	4,123	2,041	982	1,615
NET POSITION						
Net investment in capital assets	-	-	-	-	-	-
Restricted	-	-	-	-	-	-
Unrestricted	-	-	-	-	-	-
Total net position	-	-	-	-	-	-
Total liabilities and net position	$ 2,822	$ 1,397	$ 4,123	$ 2,041	$ 982	$ 1,615

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINING STATEMENTS OF NET POSITION
JUNE 30, 2015
(AMOUNTS IN THOUSANDS)

	Project Development Fund	Projects' Stabilization Fund	SCPPA Fund	Total Combined
ASSETS				
Noncurrent assets				
Net utility plant	$ -	$ -	$ 4,260	$ 1,475,962
Investments - restricted	-	146,353	-	631,010
Investments - unrestricted	-	-	-	45,125
Advance to IPA - restricted	-	-	-	11,550
Advances for capacity and energy, net - restricted	-	-	-	2,036
Fair value of derivative instruments	-	-	-	2,229
Prepaid and other assets	-	-	-	909,230
Total noncurrent assets	-	146,353	4,260	3,077,142
Current assets				
Cash and cash equivalents - restricted	6,485	10,019	165	236,950
Cash and cash equivalents - unrestricted	-	-	-	100,424
Interest receivable	-	215	-	1,278
Accounts receivable	-	-	-	11,673
Materials and supplies	-	-	-	25,909
Prepaid and other assets	-	-	-	66,624
Total current assets	6,485	10,234	165	442,858
DEFERRED OUTFLOWS OF RESOURCES				
Unamortized loss on pension assets	-	-	353	353
Unamortized loss on refunding	-	-	-	96,202
Accumulated decrease in fair value of hedging derivatives	-	-	-	23,154
Total deferred outflows of resources	-	-	353	119,709
Total assets and deferred outflows of resources	$ 6,485	$ 156,587	$ 4,778	$ 3,639,709
LIABILITIES				
Noncurrent liabilities				
Long-term debt	$ -	$ -	$ -	$ 3,176,756
Fair value of derivative instruments	-	-	-	36,857
Notes payable, other and net pension liabilities	-	-	874	9,118
Advances from participants	-	-	-	26,450
Total noncurrent liabilities	-	-	874	3,249,181
Current liabilities				
Debt due within one year	-	-	-	181,710
Notes payable and other liabilities due within one year	-	-	-	20,480
Advances from participants due within one year	6,485	-	133	45,634
Accrued interest	-	-	-	63,301
Accounts payable and accruals	-	-	33	133,067
Accrued property tax	-	-	-	5,580
Total current liabilities	6,485	-	166	449,772
Total liabilities	6,485	-	1,040	3,698,953
DEFERRED INFLOWS OF RESOURCES				
Unamortized gain on pension investments	-	-	207	207
Total deferred inflows of resources	-	-	207	207
NET POSITION				
Net investment in capital assets	-	-	4,259	(594,920)
Restricted	-	156,587	-	610,915
Unrestricted	-	-	(728)	(75,446)
Total net position	-	156,587	3,531	(59,451)
Total liabilities, deferred inflows or resources and net position	$ 6,485	$ 156,587	$ 4,778	$ 3,639,709

See accompanying notes.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINING STATEMENTS OF NET POSITION
JUNE 30, 2014
(AMOUNTS IN THOUSANDS)

	MISCELLANEOUS				
	Multiple Project Fund	Project Development Fund	Projects' Stabilization Fund	SCPPA Fund	Total Combined
ASSETS					
Noncurrent assets					
Net utility plant	$ -	$ -	$ -	$ 4,224	$ 1,574,194
Investments - restricted	-	-	130,967	-	648,532
Investments - unrestricted	-	-	-	-	31,037
Advance to IPA - restricted	-	-	-	-	11,550
Advances for capacity and energy, net - restricted	-	-	-	-	3,688
Fair value of derivative instruments	-	-	-	-	752
Prepaid and other assets	-	-	-	-	968,744
Total noncurrent assets	-	-	130,967	4,224	3,238,497
Current assets					
Cash and cash equivalents - restricted	-	65	20,826	314	205,018
Cash and cash equivalents - unrestricted	-	-	-	-	96,735
Interest receivable	-	-	234	-	3,042
Accounts receivable	-	-	-	-	17,399
Due from other project - restricted	-	-	-	-	-
Materials and supplies	-	-	-	-	24,904
Prepaid and other assets	-	-	-	-	69,603
Total current assets	-	65	21,060	314	416,701
DEFERRED OUTFLOWS OF RESOURCES					
Unamortized loss on refunding	-	-	-	-	79,668
Accumulated decrease in fair value of hedging derivatives	-	-	-	-	15,393
Total deferred outflows of resources	-	-	-	-	95,061
Total assets and deferred outflows of resources	$ -	$ 65	$ 152,027	$ 4,538	$ 3,750,259
LIABILITIES					
Noncurrent liabilities					
Long-term debt	$ -	$ -	$ -	$ -	$ 3,353,692
Fair value of derivative instruments	-	-	-	-	55,984
Notes payable and other liabilities	-	-	-	-	15,890
Advances from participants	-	-	-	-	30,907
Total noncurrent liabilities	-	-	-	-	3,456,473
Current liabilities					
Debt due within one year	-	-	-	-	158,320
Notes payable and other liabilities due within one year	-	-	-	-	15,275
Advances from participants due within one year	-	65	-	282	50,892
Accrued interest	-	-	-	-	65,396
Accounts payable and accruals	-	-	-	33	96,337
Accrued property tax	-	-	-	-	6,253
Due to other projects	-	-	-	-	-
Total current liabilities	-	65	-	315	392,473
Total liabilities	-	65	-	315	3,848,946
NET POSITION					
Net investment in capital assets	-	-	-	4,223	(608,196)
Restricted	-	-	152,027	-	583,618
Unrestricted	-	-	-	-	(74,109)
Total net position	-	-	152,027	4,223	(98,687)
Total liabilities and net position	$ -	$ 65	$ 152,027	$ 4,538	$ 3,750,259

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINING STATEMENTS OF REVENUES, EXPENSES, AND CHANGES IN NET POSITION
FOR THE YEAR ENDED JUNE 30, 2015
(AMOUNTS IN THOUSANDS)

	GENERATION				
	Palo Verde	San Juan	Magnolia Power	Canyon Power	Apex Power
Operating revenues					
Sales of electric energy	$ 76,594	$ 93,185	$ 84,917	$ 19,906	$ 110,397
Sales of transmission services	-	-	-	-	-
Sales of natural gas	-	-	-	-	-
Total operating revenues	76,594	93,185	84,917	19,906	110,397
Operating expenses					
Operations and maintenance	42,079	66,647	61,980	7,129	91,865
Depreciation, depletion and amortization	21,203	8,250	11,179	9,583	12,151
Amortization of nuclear fuel	14,493	-	-	-	-
Decommissioning	7,607	3,250	-	-	-
Total operating expenses	85,382	78,147	73,159	16,712	104,016
Operating income (loss)	(8,788)	15,038	11,758	3,194	6,381
Non operating revenues (expenses)					
Investment and other income	6,567	1,324	917	4,201	2,934
Derivative gain (loss)	-	-	(1,141)	-	-
Debt expense	(222)	(1,865)	(11,151)	(15,674)	(11,862)
Net non operating revenues (expenses)	6,345	(541)	(11,375)	(11,473)	(8,928)
Change in net position	(2,443)	14,497	383	(8,279)	(2,547)
Net position – beginning of year	249,835	31,863	(64,073)	(26,162)	(5,309)
Net contributions (distributions) by participants	-	-	-	-	-
Net position – end of year	$ 247,392	$ 46,360	$ (63,690)	$ (34,441)	$ (7,856)

See accompanying notes.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINING STATEMENTS OF REVENUES, EXPENSES, AND CHANGES IN NET POSITION
FOR THE YEAR ENDED JUNE 30, 2014
(AMOUNTS IN THOUSANDS)

	GENERATION				
	Palo Verde	San Juan	Magnolia Power	Canyon Power	Apex Power
Operating revenues					
Sales of electric energy	$ 82,369	$ 77,298	$ 101,292	$ 19,456	$ 25,517
Sales of transmission services	-	-	-	-	-
Sales of natural gas	-	-	-	-	-
Total operating revenues	82,369	77,298	101,292	19,456	25,517
Operating expenses					
Operations and maintenance	41,851	63,443	78,853	6,683	22,390
Depreciation, depletion and amortization	20,695	7,926	11,438	9,582	3,015
Amortization of nuclear fuel	16,031	-	-	-	-
Decommissioning	2,429	3,250	-	-	-
Total operating expenses	81,006	74,619	90,291	16,265	25,405
Operating income (loss)	1,363	2,679	11,001	3,191	112
Non operating revenues (expenses)					
Investment and other income	8,000	6,092	1,155	4,279	13
Derivative gain (loss)	-	-	(1,995)	-	-
Debt expense	(285)	(3,991)	(11,720)	(15,674)	(5,434)
Net non operating revenues (expenses)	7,715	2,101	(12,560)	(11,395)	(5,421)
Change in net position	9,078	4,780	(1,559)	(8,204)	(5,309)
Net position – beginning of year	240,757	27,083	(62,514)	(17,958)	-
Net contributions (distributions) by participants	-	-	-	-	-
Net position – end of year	$ 249,835	$ 31,863	$ (64,073)	$ (26,162)	$ (5,309)

See accompanying notes.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINING STATEMENTS OF REVENUES, EXPENSES, AND CHANGES IN NET POSITION
FOR THE YEAR ENDED JUNE 30, 2015
(AMOUNTS IN THOUSANDS)

	GREEN POWER					
	Hoover Uprating	Tieton Hydropower	Milford I Wind	Milford II Wind	Windy Point Project	Linden Wind Energy
Operating revenues						
Sales of electric energy	$ 2,474	$ 4,908	$ 31,204	$ 18,318	$ 76,521	$ 17,121
Sales of transmission services	-	-	-	-	-	-
Sales of natural gas	-	-	-	-	-	-
Total operating revenues	2,474	4,908	31,204	18,318	76,521	17,121
Operating expenses						
Operations and maintenance	2,835	1,601	24,000	14,156	67,324	7,797
Depreciation, depletion and amortization	-	1,472	-	-	-	5,814
Amortization of nuclear fuel	-	-	-	-	-	-
Decommissioning	-	-	-	-	-	-
Total operating expenses	2,835	3,073	24,000	14,156	67,324	13,611
Operating income (loss)	(361)	1,835	7,204	4,162	9,197	3,510
Non operating revenues (expenses)						
Investment and other income	37	141	571	29	536	856
Derivative gain (loss)	-	-	-	-	-	-
Debt expense	652	(2,454)	(8,864)	(5,325)	(15,933)	(5,524)
Net non operating revenues (expenses)	689	(2,313)	(8,293)	(5,296)	(15,397)	(4,668)
Change in net position	328	(478)	(1,089)	(1,134)	(6,200)	(1,158)
Net position - beginning of year	1,641	(4,132)	(15,307)	(4,598)	(29,305)	(5,718)
Net contributions (distributions) by participants	-	-	-	-	-	-
Net position - end of year	$ 1,969	$ (4,610)	$ (16,396)	$ (5,732)	$ (35,505)	$ (6,876)

See accompanying notes.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINING STATEMENTS OF REVENUES, EXPENSES, AND CHANGES IN NET POSITION
FOR THE YEAR ENDED JUNE 30, 2014
(AMOUNTS IN THOUSANDS)

	GREEN POWER					
	Hoover Uprating	Tieton Hydropower	Milford I Wind	Milford II Wind	Windy Point Project	Linden Wind Energy
Operating revenues						
Sales of electric energy	$ 2,535	$ 4,525	$ 29,962	$ 18,423	$ 78,446	$ 17,313
Sales of transmission services	-	-	-	-	-	-
Sales of natural gas	-	-	-	-	-	-
Total operating revenues	2,535	4,525	29,962	18,423	78,446	17,313
Operating expenses						
Operations and maintenance	3,350	1,308	22,751	14,264	69,257	7,993
Depreciation, depletion and amortization	-	1,465	-	-	-	5,814
Amortization of nuclear fuel	-	-	-	-	-	-
Decommissioning	-	-	-	-	-	-
Total operating expenses	3,350	2,773	22,751	14,264	69,257	13,807
Operating income (loss)	(815)	1,752	7,211	4,159	9,189	3,506
Non operating revenues (expenses)						
Investment and other income	62	314	471	68	232	865
Derivative gain (loss)	-	-	-	-	-	-
Debt expense	1,122	(2,481)	(9,096)	(5,357)	(16,130)	(5,565)
Net non operating revenues (expenses)	1,184	(2,167)	(8,625)	(5,289)	(15,898)	(4,700)
Change in net position	369	(415)	(1,414)	(1,130)	(6,709)	(1,194)
Net position – beginning of year	1,272	(3,717)	(13,893)	(3,468)	(22,596)	(4,524)
Net contributions (distributions) by participants	-	-	-	-	-	-
Net position – end of year	$ 1,641	$ (4,132)	$ (15,307)	$ (4,598)	$ (29,305)	$ (5,718)

See accompanying notes.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINING STATEMENTS OF REVENUES, EXPENSES, AND CHANGES IN NET POSITION
FOR THE YEAR ENDED JUNE 30, 2015
(AMOUNTS IN THOUSANDS)

	TRANSMISSION		
	Southern Transmission System	Mead- Phoenix	Mead- Adelanto
Operating revenues			
Sales of electric energy	$ -	$ -	$ -
Sales of transmission services	105,822	9,819	24,900
Sales of natural gas	-	-	-
Total operating revenues	105,822	9,819	24,900
Operating expenses			
Operations and maintenance	29,386	2,559	1,845
Depreciation, depletion and amortization	22,754	1,528	4,523
Amortization of nuclear fuel	-	-	-
Decommissioning	-	-	-
Total operating expenses	52,140	4,087	6,368
Operating income (loss)	53,682	5,732	18,532
Non operating revenues (expenses)			
Investment and other income	830	7	24
Derivative gain (loss)	28,028	-	1,477
Debt expense	(46,438)	(2,918)	(8,804)
Net non operating revenues (expenses)	(17,580)	(2,911)	(7,303)
Change in net position	36,102	2,821	11,229
Net position – beginning of year	(354,596)	(184)	(11,434)
Net contributions (distributions) by participants	-	-	-
Net position – end of year	$ (318,494)	$ 2,637	$ (205)

See accompanying notes.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINING STATEMENTS OF REVENUES, EXPENSES, AND CHANGES IN NET POSITION
FOR THE YEAR ENDED JUNE 30, 2014
(AMOUNTS IN THOUSANDS)

	TRANSMISSION		
	Southern Transmission System	Mead-Phoenix	Mead-Adelanto
Operating revenues			
Sales of electric energy	$ -	$ -	$ -
Sales of transmission services	117,170	8,257	25,659
Sales of natural gas	-	-	-
Total operating revenues	117,170	8,257	25,659
Operating expenses			
Operations and maintenance	35,269	1,264	2,098
Depreciation, depletion and amortization	22,754	1,524	4,522
Amortization of nuclear fuel	-	-	-
Decommissioning	-	-	-
Total operating expenses	58,023	2,788	6,620
Operating income (loss)	59,147	5,469	19,039
Non operating revenues (expenses)			
Investment and other income	903	3	26
Derivative gain (loss)	2,263	-	127
Debt expense	(48,112)	(3,178)	(9,429)
Net non operating revenues (expenses)	(44,946)	(3,175)	(9,276)
Change in net position	14,201	2,294	9,763
Net position – beginning of year	(368,797)	3,906	(2,760)
Net contributions (distributions) by participants	-	(6,384)	(18,437)
Net position – end of year	$ (354,596)	$ (184)	$ (11,434)

See accompanying notes.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINING STATEMENTS OF REVENUES, EXPENSES, AND CHANGES IN NET POSITION
FOR THE YEAR ENDED JUNE 30, 2015
(AMOUNTS IN THOUSANDS)

	NATURAL GAS		
	Pinedale	Barnett	Prepaid Natural Gas
Operating revenues			
Sales of electric energy	$ -	$ -	$ -
Sales of transmission services	-	-	-
Sales of natural gas	8,409	16,039	19,591
Total operating revenues	8,409	16,039	19,591
Operating expenses			
Operations and maintenance	3,106	8,046	11,735
Depreciation, depletion and amortization	4,105	3,915	-
Amortization of nuclear fuel	-	-	-
Decommissioning	-	-	-
Total operating expenses	7,211	11,961	11,735
Operating income (loss)	1,198	4,078	7,856
Non operating revenues (expenses)			
Investment and other income	5	374	697
Derivative gain (loss)	-	-	-
Debt expense	(1,388)	(3,264)	(16,220)
Net non operating revenues (expenses)	(1,383)	(2,890)	(15,523)
Change in net position	(185)	1,188	(7,667)
Net position – beginning of year	5,045	21,906	(44,409)
Net contributions (distributions) by participants	-	-	-
Net position – end of year	$ 4,860	$ 23,094	$ (52,076)

 See accompanying notes.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINING STATEMENTS OF REVENUES, EXPENSES, AND CHANGES IN NET POSITION
FOR THE YEAR ENDED JUNE 30, 2014
(AMOUNTS IN THOUSANDS)

	NATURAL GAS		
	Pinedale	Barnett	Prepaid Natural Gas
Operating revenues			
Sales of electric energy	$ -	$ -	$ -
Sales of transmission services	-	-	-
Sales of natural gas	9,951	20,116	16,312
Total operating revenues	9,951	20,116	16,312
Operating expenses			
Operations and maintenance	4,018	10,601	11,754
Depreciation, depletion and amortization	5,046	4,070	-
Amortization of nuclear fuel	-	-	-
Decommissioning	-	-	-
Total operating expenses	9,064	14,671	11,754
Operating income (loss)	887	5,445	4,558
Non operating revenues (expenses)			
Investment and other income	5	591	4,092
Derivative gain (loss)	-	-	-
Debt expense	(1,490)	(3,503)	(16,406)
Net non operating revenues (expenses)	(1,485)	(2,912)	(12,314)
Change in net position	(598)	2,533	(7,756)
Net position – beginning of year	5,643	19,373	(36,653)
Net contributions (distributions) by participants	-	-	-
Net position – end of year	$ 5,045	$ 21,906	$ (44,409)

See accompanying notes.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINING STATEMENTS OF REVENUES, EXPENSES, AND CHANGES IN NET POSITION
FOR THE YEAR ENDED JUNE 30, 2015
(AMOUNTS IN THOUSANDS)

	POWER PURCHASE AGREEMENTS						
	Ormat Geothermal	MWD Small Hydro	Pebble Springs	Ameresco Chiquita Landfill Gas	Don A. Campbell Wild Rose Geothermal	Copper Mountain Solar 3	Columbia Solar 2
Operating revenues							
Sales of electric energy	$ 7,208	$ 2,379	$ 19,351	$ 2,924	$ 15,765	$ 43,675	$ 1,668
Sales of transmission services	-	-	-	-	-	-	-
Sales of natural gas	-	-	-	-	-	-	-
Total operating revenues	7,208	2,379	19,351	2,924	15,765	43,675	1,668
Operating expenses							
Operations and maintenance	7,211	2,381	19,351	2,924	15,765	43,682	1,668
Depreciation, depletion and amortization	-	-	-	-	-	-	-
Amortization of nuclear fuel	-	-	-	-	-	-	-
Decommissioning	-	-	-	-	-	-	-
Total operating expenses	7,211	2,381	19,351	2,924	15,765	43,682	1,668
Operating income (loss)	(3)	(2)	-	-	-	(7)	-
Non operating revenues (expenses)							
Investment and other income	3	2	-	-	-	7	-
Derivative gain (loss)	-	-	-	-	-	-	-
Debt expense	-	-	-	-	-	-	-
Net non operating revenues (expenses)	3	2	-	-	-	7	-
Change in net position	-	-	-	-	-	-	-
Net position – beginning of year	-	-	-	-	-	-	-
Net contributions (distributions) by participants	-	-	-	-	-	-	-
Net position – end of year	$ -	$ -	$ -	$ -	$ -	$ -	$ -

 See accompanying notes.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINING STATEMENTS OF REVENUES, EXPENSES, AND CHANGES IN NET POSITION
FOR THE YEAR ENDED JUNE 30, 2014
(AMOUNTS IN THOUSANDS)

	POWER PURCHASE AGREEMENTS					
	Ormat Geothermal	MWD Small Hydro	Pebble Springs	Ameresco Chiquita Landfill Gas	Don A. Campbell Wild Rose Geothermal	Copper Mountain Solar 3
Operating revenues						
Sales of electric energy	$ 7,768	$ 3,009	$ 23,222	$ 2,954	$ 9,350	$ 1,423
Sales of transmission services	-	-	-	-	-	-
Sales of natural gas	-	-	-	-	-	-
Total operating revenues	7,768	3,009	23,222	2,954	9,350	1,423
Operating expenses						
Operations and maintenance	7,774	3,011	23,227	2,954	9,350	1,423
Depreciation, depletion and amortization	-	-	-	-	-	-
Amortization of nuclear fuel	-	-	-	-	-	-
Decommissioning	-	-	-	-	-	-
Total operating expenses	7,774	3,011	23,227	2,954	9,350	1,423
Operating income (loss)	(6)	(2)	(5)	-	-	-
Non operating revenues (expenses)						
Investment and other income	6	2	5	-	-	-
Derivative gain (loss)	-	-	-	-	-	-
Debt expense	-	-	-	-	-	-
Net non operating revenues (expenses)	6	2	5	-	-	-
Change in net position	-	-	-	-	-	-
Net position – beginning of year	-	-	-	-	-	-
Net contributions (distributions) by participants	-	-	-	-	-	-
Net position – end of year	$ -	$ -	$ -	$ -	$ -	$ -

See accompanying notes.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINING STATEMENTS OF REVENUES, EXPENSES, AND CHANGES IN NET POSITION
FOR THE YEAR ENDED JUNE 30, 2015
(AMOUNTS IN THOUSANDS)

	MISCELLANEOUS			
	Project Development Fund	Projects' Stabilization Fund	SCPPA Fund	Total Combined
Operating revenues				
Sales of electric energy	$ -	$ -	$ -	$ 628,515
Sales of transmission services	-	-	-	140,541
Sales of natural gas	-	-	-	44,039
Total operating revenues	-	-	-	813,095
Operating expenses				
Operations and maintenance	-	-	144	537,216
Depreciation, depletion and amortization	-	-	113	106,590
Amortization of nuclear fuel	-	-	-	14,493
Decommissioning	-	-	-	10,857
Pension expense (credit)	-	-	(276)	(276)
Total operating expenses	-	-	(19)	668,880
Operating income (loss)	-	-	19	144,215
Non operating revenues (expenses)				
Investment and other income	-	1,703	144	21,909
Derivative gain (loss)	-	-	-	28,364
Debt expense	-	-	-	(157,254)
Net non operating revenues (expenses)	-	1,703	144	(106,981)
Change in net position	-	1,703	163	37,234
Net position – beginning of year, before adjustment	-	152,027	4,223	(98,687)
Less: Accumulated adjustment for change in accounting principal	-	-	(1,004)	(1,004)
Net position – beginning of year, as adjusted	-	152,027	3,219	(99,691)
Net contributions (distributions) by participants	-	2,857	149	3,006
Net position – end of year	$ -	$ 156,587	$ 3,531	$ (59,451)

See accompanying notes.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINING STATEMENTS OF REVENUES, EXPENSES, AND CHANGES IN NET POSITION
FOR THE YEAR ENDED JUNE 30, 2014
(AMOUNTS IN THOUSANDS)

	MISCELLANEOUS				
	Multiple Project Fund	Project Development Fund	Projects' Stabilization Fund	SCPPA Fund	Total Combined
Operating revenues					
Sales of electric energy	$ -	$ -	$ -	$ -	$ 504,862
Sales of transmission services	-	-	-	-	151,086
Sales of natural gas	-	-	-	-	46,379
Total operating revenues	-	-	-	-	702,327
Operating expenses					
Operations and maintenance	-	-	-	130	445,016
Depreciation, depletion and amortization	-	-	-	113	97,964
Amortization of nuclear fuel	-	-	-	-	16,031
Decommissioning	-	-	-	-	5,679
Total operating expenses	-	-	-	243	564,690
Operating income (loss)	-	-	-	(243)	137,637
Non operating revenues (expenses)					
Investment and other income	-	-	2,752	130	30,066
Derivative gain (loss)	-	-	-	-	395
Debt expense	-	-	-	-	(156,729)
Net non operating revenues (expenses)	-	-	2,752	130	(126,268)
Change in net position	-	-	2,752	(113)	11,369
Net position – beginning of year	-	-	127,583	4,264	(106,999)
Cumulative effect of change in pension	-	-	-	-	-
Net position – beginning of year	-	-	127,583	4,264	(106,999)
Net contributions (distributions) by participants	-	-	21,692	72	(3,057)
Net position – end of year	$ -	$ -	$ 152,027	$ 4,223	$ (98,687)

See accompanying notes.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINING STATEMENTS OF CASH FLOWS
FOR THE YEAR ENDED JUNE 30, 2015
(AMOUNTS IN THOUSANDS)

	GENERATION				
	Palo Verde	San Juan	Magnolia Power	Canyon Power	Apex Power
Cash flows from operating activities					
Receipts from participants	$ 81,113	$ 87,760	$ 49,127	$ 15,323	$ 53,914
Receipts from sale of oil and gas	-	-	-	-	-
Payments to operating managers	(44,522)	(65,534)	(26,527)	(2,386)	(32,543)
Other disbursements and receipts	13,513	-	-	-	3,460
Net cash flows from operating activities	50,104	22,226	22,600	12,937	24,831
Cash flows from noncapital financing activities					
Advances (withdrawals) by participants, net	-	-	-	-	21
Cash flows from capital financing activities					
Additions to plant and prepaid projects, net	(31,134)	(114)	(1,331)	(128)	(536)
Debt interest and swap payments	(203)	(3,724)	(11,368)	(11,220)	(9,632)
Proceeds from sale of bonds	-	42,935	-	-	-
Payment for defeasance of revenue bonds	-	(71,880)	-	-	-
Transfer of funds from (to) escrow	-	-	-	-	-
Transfer of funds from (to) Mine Reclamation Trust Fund	-	(420)	-	-	-
Transfer of funds from (to) other projects	-	-	-	-	-
Principal payments on debt	(11,330)	-	(10,565)	-	-
Payment for bond issue costs	-	(313)	-	-	-
Net cash used for capital and related financing activities	(42,667)	(33,516)	(23,264)	(11,348)	(10,168)
Cash flows from investing activities					
Interest received on investments	286	232	748	282	157
Purchases of investments	(17,490)	(26,480)	(36,631)	(3,195)	(65,540)
Proceeds from sale/maturity of investments	26,250	36,198	39,840	4,000	51,070
Net cash provided by (used for) investing activities	9,046	9,950	3,957	1,087	(14,313)
Net increase (decrease) in cash and cash equivalents	16,483	(1,340)	3,293	2,676	371
Cash and cash equivalents, beginning of year	17,292	22,328	33,745	9,273	33,736
Cash and cash equivalents, end of year	$ 33,775	$ 20,988	$ 37,038	$ 11,949	$ 34,107
Reconciliation of operating income (loss) to net cash provided by operating activities					
Operating income (loss)	$ (8,788)	$ 15,038	$ 11,758	$ 3,194	$ 6,381
Adjustments to reconcile operating income (loss) to net cash provided by operating activities					
Depreciation, depletion and amortization	21,203	8,250	11,179	9,583	12,690
Decommissioning	7,607	3,250	-	-	-
Advances for capacity and energy	-	-	-	-	-
Amortization of nuclear fuel	14,493	-	-	-	-
Changes in assets and liabilities					
Accounts receivable	3,197	(205)	1,266	(28)	-
Accounts payable and accruals	7,071	(4,810)	(766)	232	4,243
Other	5,321	703	(837)	(44)	1,517
Net cash provided by operating activities	$ 50,104	$ 22,226	$ 22,600	$ 12,937	$ 24,831
Cash and cash equivalents as stated in the Combined Statements of Net Position					
Cash and cash equivalents - restricted	$ 22,159	$ 15,075	$ 29,108	$ 11,299	$ 16,667
Cash and cash equivalents - unrestricted	11,616	5,913	7,930	650	17,440
	$ 33,775	$ 20,988	$ 37,038	$ 11,949	$ 34,107

See accompanying notes.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINING STATEMENTS OF CASH FLOWS
FOR THE YEAR ENDED JUNE 30, 2014
(AMOUNTS IN THOUSANDS)

	GENERATION				
	Palo Verde	San Juan	Magnolia Power	Canyon Power	Apex Power
Cash flows from operating activities					
Receipts from participants	$ 75,291	$ 86,764	$ 54,969	$ 16,033	$ 27,836
Receipts from sale of oil and gas	-	-	-	-	-
Payments to operating managers	(39,630)	(58,591)	(25,900)	(2,416)	(6,252)
Other disbursements and receipts	7,633	-	-	-	173
Net cash flows from operating activities	43,294	28,173	29,069	13,617	21,757
Cash flows from noncapital financing activities					
Advances (withdrawals) by participants, net	-	-	-	-	-
Cash flows from capital financing activities					
Additions to plant and prepaid projects, net	(28,446)	(1,681)	(920)	(7,032)	(296,120)
Debt interest and swap payments	(275)	(5,093)	(12,100)	(14,893)	-
Proceeds from sale of bonds	-	-	-	-	333,872
Payment for defeasance of revenue bonds	-	-	-	-	-
Transfer of funds from (to) escrow	-	-	-	-	-
Transfer of funds from (to) Mine Reclamation Trust Fund	-	(489)	-	-	-
Transfer of funds from (to) other projects	-	-	-	-	-
Principal payments on debt	(10,980)	(27,250)	(15,605)	-	-
Payment for bond issue costs	-	-	-	-	(2,293)
Net cash used for capital and related financing activities	(39,701)	(34,513)	(28,625)	(21,925)	35,459
Cash flows from investing activities					
Interest received on investments	255	799	660	290	5
Purchases of investments	(22,921)	(32,898)	(41,566)	(15,967)	(23,485)
Proceeds from sale/maturity of investments	12,030	43,434	39,160	23,875	-
Net cash provided by (used for) investing activities	(10,636)	11,335	(1,746)	8,198	(23,480)
Net increase (decrease) in cash and cash equivalents	(7,043)	4,995	(1,302)	(110)	33,736
Cash and cash equivalents, beginning of year	24,335	17,333	35,047	9,383	-
Cash and cash equivalents, end of year	$ 17,292	$ 22,328	$ 33,745	$ 9,273	$ 33,736
Reconciliation of operating income (loss) to net cash provided by operating activities					
Operating income (loss)	$ 1,363	$ 2,679	$ 11,001	$ 3,191	$ 112
Adjustments to reconcile operating income (loss) to net cash provided by operating activities					
Depreciation, depletion and amortization	20,695	7,926	11,438	9,582	3,214
Decommissioning	2,429	3,250	-	-	-
Advances for capacity and energy	-	-	-	-	-
Amortization of nuclear fuel	16,031	-	-	-	-
Changes in assets and liabilities					
Accounts receivable	(139)	50	(1,025)	1,010	-
Accounts payable and accruals	3,125	9,586	4,059	(193)	18,712
Other	(210)	4,682	3,596	27	(281)
Net cash provided by operating activities	$ 43,294	$ 28,173	$ 29,069	$ 13,617	$ 21,757
Cash and cash equivalents as stated in the Combined Statements of Net Position					
Cash and cash equivalents - restricted	$ 9,869	$ 8,596	$ 27,618	$ 7,576	$ 16,306
Cash and cash equivalents - unrestricted	7,423	13,732	6,127	1,697	17,430
	$ 17,292	$ 22,328	$ 33,745	$ 9,273	$ 33,736

See accompanying notes.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINING STATEMENTS OF CASH FLOWS
FOR THE YEAR ENDED JUNE 30, 2015
(AMOUNTS IN THOUSANDS)

	GREEN POWER					
	Hoover Uprating	Tieton Hydropower	Milford I Wind	Milford II Wind	Windy Point Project	Linden Wind Energy
Cash flows from operating activities						
Receipts from participants	$ 2,539	$ 4,885	$ 26,928	$ 17,690	$ 76,460	$ 16,697
Receipts from sale of oil and gas	-	-	-	-	-	-
Payments to operating managers	(308)	(1,782)	(12,662)	(5,589)	(34,222)	(7,830)
Other disbursements and receipts	-	-	-	-	-	-
Net cash flows from operating activities	2,231	3,103	14,266	12,101	42,238	8,867
Cash flows from noncapital financing activities						
Advances (withdrawals) by participants, net	-	-	-	-	-	-
Cash flows from capital financing activities						
Additions to plant and prepaid projects, net	-	-	-	-	-	-
Debt interest and swap payments	(368)	(2,532)	(10,236)	(7,463)	(22,081)	(5,357)
Proceeds from sale of bonds	-	-	-	-	-	-
Payment for defeasance of revenue bonds	-	-	-	-	-	-
Transfer of funds from (to) escrow	-	-	-	-	-	-
Transfer of funds from (to) Mine Reclamation Trust Fund	-	-	-	-	-	-
Transfer of funds from (to) other projects	-	-	-	-	-	-
Principal payments on debt	(1,835)	(815)	(8,450)	(5,270)	(18,535)	(3,530)
Payment for bond issue costs	-	-	-	-	-	-
Net cash used for capital and related financing activities	(2,203)	(3,347)	(18,686)	(12,733)	(40,616)	(8,887)
Cash flows from investing activities						
Interest received on investments	24	69	317	56	194	31
Purchases of investments	(1,999)	-	(15,445)	(5,526)	(22,992)	(5,584)
Proceeds from sale/maturity of investments	1,860	500	18,149	6,400	21,499	6,478
Net cash provided by (used for) investing activities	(115)	569	3,021	930	(1,299)	925
Net increase (decrease) in cash and cash equivalents	(87)	325	(1,399)	298	323	905
Cash and cash equivalents, beginning of year	968	2,808	15,198	11,304	24,882	7,306
Cash and cash equivalents, end of year	$ 881	$ 3,133	$ 13,799	$ 11,602	$ 25,205	$ 8,211
Reconciliation of operating income (loss) to net cash provided by operating activities						
Operating income (loss)	$ (361)	$ 1,835	$ 7,204	$ 4,162	$ 9,197	$ 3,510
Adjustments to reconcile operating income (loss) to net cash provided by operating activities						
Depreciation, depletion and amortization	-	1,472	11,338	8,643	31,635	5,814
Decommissioning	-	-	-	-	-	-
Advances for capacity and energy	2,550	-	-	-	-	-
Amortization of nuclear fuel	-	-	-	-	-	-
Changes in assets and liabilities						
Accounts receivable	-	-	-	-	-	(129)
Accounts payable and accruals	56	203	(4,267)	(696)	1,073	(318)
Other	(14)	(407)	(9)	(8)	333	(10)
Net cash provided by operating activities	$ 2,231	$ 3,103	$ 14,266	$ 12,101	$ 42,238	$ 8,867
Cash and cash equivalents as stated in the Combined Statements of Net Position						
Cash and cash equivalents - restricted	$ 89	$ 2,554	$ 11,855	$ 9,199	$ 19,228	$ 7,988
Cash and cash equivalents - unrestricted	792	579	1,944	2,403	5,977	223
	$ 881	$ 3,133	$ 13,799	$ 11,602	$ 25,205	$ 8,211

See accompanying notes.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINING STATEMENTS OF CASH FLOWS
FOR THE YEAR ENDED JUNE 30, 2014
(AMOUNTS IN THOUSANDS)

	GREEN POWER					
	Hoover Uprating	Tieton Hydropower	Milford I Wind	Milford II Wind	Windy Point Project	Linden Wind Energy
Cash flows from operating activities						
Receipts from participants	$ 2,583	$ 4,459	$ 30,544	$ 16,508	$ 79,488	$ 17,292
Receipts from sale of oil and gas	-	-	-	-	-	-
Payments to operating managers	(308)	(1,177)	(12,133)	(5,647)	(38,077)	(9,836)
Other disbursements and receipts	-	155	643	-	-	-
Net cash flows from operating activities	2,275	3,437	19,054	10,861	41,411	7,456
Cash flows from noncapital financing activities						
Advances (withdrawals) by participants, net	-	-	-	-	-	-
Cash flows from capital financing activities						
Additions to plant and prepaid projects, net	-	(81)	-		-	-
Debt interest and swap payments	(455)	(2,556)	(10,581)	(7,696)	(22,850)	(6,277)
Proceeds from sale of bonds	-	-	-	-	-	-
Payment for defeasance of revenue bonds	-	-	-	-	-	-
Transfer of funds from (to) escrow	-	-	-	-	-	-
Transfer of funds from (to) Mine Reclamation Trust Fund	-	-	-	-	-	-
Transfer of funds from (to) other projects	-	-	-	-	-	-
Principal payments on debt	(1,755)	(790)	(8,135)	(5,065)	(17,850)	(3,425)
Payment for bond issue costs	-	-	-	-	-	-
Net cash used for capital and related financing activities	(2,210)	(3,427)	(18,716)	(12,761)	(40,700)	(9,702)
Cash flows from investing activities						
Interest received on investments	22	69	320	54	208	29
Purchases of investments	(1,860)	(500)	(19,842)	(9,696)	(30,279)	(6,232)
Proceeds from sale/maturity of investments	1,860	500	22,343	16,100	36,873	10,485
Net cash provided by (used for) investing activities	22	69	2,821	6,458	6,802	4,282
Net increase (decrease) in cash and cash equivalents	87	79	3,159	4,558	7,513	2,036
Cash and cash equivalents, beginning of year	881	2,729	12,039	6,746	17,369	5,270
Cash and cash equivalents, end of year	$ 968	$ 2,808	$ 15,198	$ 11,304	$ 24,882	$ 7,306
Reconciliation of operating income (loss) to net cash provided by operating activities						
Operating income (loss)	$ (815)	$ 1,752	$ 7,211	$ 4,159	$ 9,189	$ 3,506
Adjustments to reconcile operating income (loss) to net cash provided by operating activities						
Depreciation, depletion and amortization	-	1,465	11,338	8,643	31,635	5,814
Decommissioning	-	-	-	-	-	-
Advances for capacity and energy	3,031	-	-	-	-	-
Amortization of nuclear fuel	-	-	-	-	-	-
Changes in assets and liabilities						
Accounts receivable	38	-	-	-	-	-
Accounts payable and accruals	21	-	502	(1,941)	587	(1,864)
Other	-	220	3	-	-	-
Net cash provided by operating activities	$ 2,275	$ 3,437	$ 19,054	$ 10,861	$ 41,411	$ 7,456
Cash and cash equivalents as stated in the Combined Statements of Net Position						
Cash and cash equivalents - restricted	$ 181	$ 2,124	$ 6,475	$ 5,372	$ 17,307	$ 4,772
Cash and cash equivalents - unrestricted	787	684	8,723	5,932	7,575	2,534
	$ 968	$ 2,808	$ 15,198	$ 11,304	$ 24,882	$ 7,306

See accompanying notes.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINING STATEMENTS OF CASH FLOWS
FOR THE YEAR ENDED JUNE 30, 2015
(AMOUNTS IN THOUSANDS)

	TRANSMISSION		
	Southern Transmission System	Mead-Phoenix	Mead-Adelanto
Cash flows from operating activities			
Receipts from participants	$ 106,683	$ 10,408	$ 24,953
Receipts from sale of oil and gas	-	-	-
Payments to operating managers	(23,911)	(2,709)	(1,813)
Other disbursements and receipts	-	2	2
Net cash flows from operating activities	82,772	7,701	23,142
Cash flows from noncapital financing activities			
Advances (withdrawals) by participants, net	-	-	-
Cash flows from capital financing activities			
Additions to plant and prepaid projects, net	-	(128)	(38)
Debt interest and swap payments	(31,347)	(1,507)	(5,491)
Proceeds from sale of bonds	273,160	-	-
Payment for defeasance of revenue bonds	(277,790)	-	-
Transfer of funds from (to) escrow	-	-	-
Transfer of funds from (to) Mine Reclamation Trust Fund	-	-	-
Transfer of funds from (to) other projects	-	-	-
Principal payments on debt	(50,885)	-	-
Payment for bond issue costs	(1,237)	(5,215)	(17,385)
Net cash used for capital and related financing activities	(88,099)	(6,850)	(22,914)
Cash flows from investing activities			
Interest received on investments	709	2	8
Purchases of investments	(55,871)	(2,898)	(22,234)
Proceeds from sale/maturity of investments	73,207	2,300	25,750
Net cash provided by (used for) investing activities	18,045	(596)	3,524
Net increase (decrease) in cash and cash equivalents	12,718	255	3,752
Cash and cash equivalents, beginning of year	32,731	4,422	10,408
Cash and cash equivalents, end of year	$ 45,449	$ 4,677	$ 14,160
Reconciliation of operating income (loss) to net cash provided by operating activities			
Operating income (loss)	$ 53,682	$ 5,732	$ 18,532
Adjustments to reconcile operating income (loss) to net cash provided by operating activities			
Depreciation, depletion and amortization	22,754	1,528	4,523
Decommissioning	-	-	-
Advances for capacity and energy	-	-	-
Amortization of nuclear fuel	-	-	-
Changes in assets and liabilities			
Accounts receivable	(603)	98	15
Accounts payable and accruals	6,959	450	84
Other	(20)	(107)	(12)
Net cash provided by operating activities	$ 82,772	$ 7,701	$ 23,142
Cash and cash equivalents as stated in the Combined Statements of Net Position			
Cash and cash equivalents - restricted	$ 40,466	$ 2,358	$ 12,098
Cash and cash equivalents - unrestricted	4,983	2,319	2,062
	$ 45,449	$ 4,677	$ 14,160

See accompanying notes.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINING STATEMENTS OF CASH FLOWS
FOR THE YEAR ENDED JUNE 30, 2014
(AMOUNTS IN THOUSANDS)

	TRANSMISSION		
	Southern Transmission System	Mead-Phoenix	Mead-Adelanto
Cash flows from operating activities			
Receipts from participants	$ 112,691	$ 8,524	$ 25,736
Receipts from sale of oil and gas	-	-	-
Payments to operating managers	(35,406)	(1,511)	(2,392)
Other disbursements and receipts	-	-	-
Net cash flows from operating activities	77,285	7,013	23,344
Cash flows from noncapital financing activities			
Advances (withdrawals) by participants, net	-	-	-
Cash flows from capital financing activities			
Additions to plant and prepaid projects, net	(91)	(53)	-
Debt interest and swap payments	(32,721)	(1,816)	(6,427)
Proceeds from sale of bonds	-	-	-
Payment for defeasance of revenue bonds	-	-	-
Transfer of funds from (to) escrow	-	-	-
Transfer of funds from (to) Mine Reclamation Trust Fund	-	-	-
Transfer of funds from (to) other projects	-	350	1,200
Principal payments on debt	(49,130)	(6,505)	(17,820)
Payment for bond issue costs	(215)	-	-
Net cash used for capital and related financing activities	(82,157)	(8,024)	(23,047)
Cash flows from investing activities			
Interest received on investments	756	206	841
Purchases of investments	(82,225)	(2,300)	(27,783)
Proceeds from sale/maturity of investments	82,685	5,868	32,587
Net cash provided by (used for) investing activities	1,216	3,774	5,645
Net increase (decrease) in cash and cash equivalents	(3,656)	2,763	5,942
Cash and cash equivalents, beginning of year	36,387	1,659	4,466
Cash and cash equivalents, end of year	$ 32,731	$ 4,422	$ 10,408
Reconciliation of operating income (loss) to net cash provided by operating activities			
Operating income (loss)	$ 59,147	$ 5,469	$ 19,039
Adjustments to reconcile operating income (loss) to net cash provided by operating activities			
Depreciation, depletion and amortization	22,754	1,524	4,522
Decommissioning	-	-	-
Advances for capacity and energy	-	-	-
Amortization of nuclear fuel	-	-	-
Changes in assets and liabilities			
Accounts receivable	(3,835)	39	31
Accounts payable and accruals	(781)	13	38
Other	-	(32)	(286)
Net cash provided by operating activities	$ 77,285	$ 7,013	$ 23,344
Cash and cash equivalents as stated in the Combined Statements of Net Position			
Cash and cash equivalents - restricted	$ 32,585	$ 4,100	$ 10,050
Cash and cash equivalents - unrestricted	146	322	358
	$ 32,731	$ 4,422	$ 10,408

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINING STATEMENTS OF CASH FLOWS
FOR THE YEAR ENDED JUNE 30, 2015
(AMOUNTS IN THOUSANDS)

	NATURAL GAS		
	Pinedale	Barnett	Prepaid Natural Gas
Cash flows from operating activities			
Receipts from participants	$ 4,061	$ 9,782	$ 7,429
Receipts from sale of oil and gas	2,063	4,510	9,713
Payments to operating managers	(4,542)	(5,872)	(476)
Other disbursements and receipts	14	-	-
Net cash flows from operating activities	1,596	8,420	16,666
Cash flows from noncapital financing activities			
Advances (withdrawals) by participants, net	(7,805)	(47)	-
Cash flows from capital financing activities			
Additions to plant and prepaid projects, net	(122)	(636)	-
Debt interest and swap payments	(1,440)	(3,384)	(15,857)
Proceeds from sale of bonds	-	-	-
Payment for defeasance of revenue bonds	-	-	-
Transfer of funds from (to) escrow	-	-	-
Transfer of funds from (to) Mine Reclamation Trust Fund	-	-	-
Transfer of funds from (to) other projects	-	-	-
Principal payments on debt	(2,219)	(5,211)	(3,875)
Payment for bond issue costs	-	-	-
Net cash used for capital and related financing activities	(3,781)	(9,231)	(19,732)
Cash flows from investing activities			
Interest received on investments	3	228	688
Purchases of investments	-	(9,498)	(16,077)
Proceeds from sale/maturity of investments	-	6,400	16,069
Net cash provided by (used for) investing activities	3	(2,870)	680
Net increase (decrease) in cash and cash equivalents	(9,987)	(3,728)	(2,386)
Cash and cash equivalents, beginning of year	19,290	16,109	6,862
Cash and cash equivalents, end of year	$ 9,303	$ 12,381	$ 4,476
Reconciliation of operating income (loss) to net cash provided by operating activities			
Operating income (loss)	$ 1,198	$ 4,078	$ 7,856
Adjustments to reconcile operating income (loss) to net cash provided by operating activities			
Depreciation, depletion and amortization	4,105	3,915	-
Decommissioning	-	-	-
Advances for capacity and energy	-	-	-
Amortization of nuclear fuel	-	-	-
Changes in assets and liabilities			
Accounts receivable	(702)	936	(17)
Accounts payable and accruals	(1,234)	(90)	(2,448)
Other	(1,771)	(419)	11,275
Net cash provided by operating activities	$ 1,596	$ 8,420	$ 16,666
Cash and cash equivalents as stated in the Combined Statements of Net Position			
Cash and cash equivalents - restricted	$ 4,607	$ 11,117	$ 4,399
Cash and cash equivalents - unrestricted	4,696	1,264	77
	$ 9,303	$ 12,381	$ 4,476

See accompanying notes.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINING STATEMENTS OF CASH FLOWS
FOR THE YEAR ENDED JUNE 30, 2014
(AMOUNTS IN THOUSANDS)

	NATURAL GAS		
	Pinedale	Barnett	Prepaid Natural Gas
Cash flows from operating activities			
Receipts from participants	$ 5,015	$ 10,196	$ 8,614
Receipts from sale of oil and gas	3,247	5,905	-
Payments to operating managers	(3,912)	(6,448)	(1,632)
Other disbursements and receipts	(7)	-	13,430
Net cash flows from operating activities	4,343	9,653	20,412
Cash flows from noncapital financing activities			
Advances (withdrawals) by participants, net	3,236	399	-
Cash flows from capital financing activities			
Additions to plant and prepaid projects, net	(586)	(536)	-
Debt interest and swap payments	(1,538)	(3,619)	(16,056)
Proceeds from sale of bonds	-	-	-
Payment for defeasance of revenue bonds	-	-	-
Transfer of funds from (to) escrow	-	-	-
Transfer of funds from (to) Mine Reclamation Trust Fund	-	-	-
Transfer of funds from (to) other projects	-	-	-
Principal payments on debt	(2,253)	(5,302)	(4,065)
Payment for bond issue costs	-	-	-
Net cash used for capital and related financing activities	(4,377)	(9,457)	(20,121)
Cash flows from investing activities			
Interest received on investments	5	251	691
Purchases of investments	(1,200)	(17,000)	(27,435)
Proceeds from sale/maturity of investments	1,800	23,800	27,365
Net cash provided by (used for) investing activities	605	7,051	621
Net increase (decrease) in cash and cash equivalents	3,807	7,646	912
Cash and cash equivalents, beginning of year	15,483	8,463	5,950
Cash and cash equivalents, end of year	$ 19,290	$ 16,109	$ 6,862
Reconciliation of operating income (loss) to net cash provided by operating activities			
Operating income (loss)	$ 887	$ 5,445	$ 4,558
Adjustments to reconcile operating income (loss) to net cash provided by operating activities			
Depreciation, depletion and amortization	5,046	4,070	-
Decommissioning	-	-	-
Advances for capacity and energy	-	-	-
Amortization of nuclear fuel	-	-	-
Changes in assets and liabilities			
Accounts receivable	52	(182)	28
Accounts payable and accruals	528	404	1,109
Other	(2,170)	(84)	14,717
Net cash provided by operating activities	$ 4,343	$ 9,653	$ 20,412
Cash and cash equivalents as stated in the Combined Statements of Net Position			
Cash and cash equivalents – restricted	$ 10,055	$ 13,988	$ 6,839
Cash and cash equivalents – unrestricted	9,235	2,121	23
	$ 19,290	$ 16,109	$ 6,862

See accompanying notes.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINING STATEMENTS OF CASH FLOWS
FOR THE YEAR ENDED JUNE 30, 2015
(AMOUNTS IN THOUSANDS)

	POWER PURCHASE AGREEMENTS						
	Ormat Geothermal Energy	MWD Small Hydro	Pebble Springs	Ameresco Chiquita Landfill Gas	Don A. Campbell Wild Rose Geothermal	Copper Mountain Solar 3	Columbia Solar 2
Cash flows from operating activities							
Receipts from participants	$ 6,345	$ 2,372	$ 19,271	$ 2,354	$ 18,951	$ 53,181	$ 2,430
Receipts from sale of oil and gas	-	-	-	-	-	-	-
Payments to operating managers	(7,354)	(2,262)	(19,633)	(2,977)	(15,649)	(27,833)	(1,065)
Other disbursements and receipts	3	6	-	-	-	-	520
Net cash flows from operating activities	(1,006)	116	(362)	(623)	3,302	25,348	1,885
Cash flows from noncapital financing activities							
Advances (withdrawals) by participants, net	-	-	-	-	-	-	-
Cash flows from capital financing activities							
Additions to plant and prepaid projects, net	-	-	-	-	-	-	-
Debt interest and swap payments	-	-	-	-	-	-	-
Proceeds from sale of bonds	-	-	-	-	-	-	-
Payment for defeasance of revenue bonds	-	-	-	-	-	-	-
Transfer of funds from (to) escrow	-	-	-	-	-	-	-
Transfer of funds from (to) Mine Reclamation Trust Fund	-	-	-	-	-	-	-
Transfer of funds from (to) other projects	-	-	-	-	-	-	-
Principal payments on debt	-	-	-	-	-	-	-
Payment for bond issue costs	-	-	-	-	-	-	-
Net cash used for capital and related financing activities	-	-	-	-	-	-	-
Cash flows from investing activities							
Interest received on investments	4	2	-	-	-	8	-
Purchases of investments	-	-	(1,000)	-	-	(14,989)	-
Proceeds from sale/maturity of investments	-	-	-	-	-	5,000	-
Net cash provided by (used for) investing activities	4	2	(1,000)	-	-	(9,981)	-
Net increase (decrease) in cash and cash equivalents	(1,002)	118	(1,362)	(623)	3,302	15,367	1,885
Cash and cash equivalents, beginning of year	2,819	1,221	4,123	2,041	67	1,615	-
Cash and cash equivalents, end of year	$ 1,817	$ 1,339	$ 2,761	$ 1,418	$ 3,369	$ 16,982	$ 1,885
Reconciliation of operating income (loss) to net cash provided by operating activities							
Operating income (loss)	$ (3)	$ (2)	$ -	$ -	$ -	$ (7)	$ -
Adjustments to reconcile operating income (loss) to net cash provided by operating activities							
Depreciation, depletion and amortization	-	-	-	-	-	-	-
Decommissioning	-	-	-	-	-	-	-
Advances for capacity and energy	-	-	-	-	-	-	-
Amortization of nuclear fuel	-	-	-	-	-	-	-
Changes in assets and liabilities							
Accounts receivable	(140)	(85)	-	-	915	-	(37)
Accounts payable and accruals	(864)	197	(356)	(623)	2,387	25,359	1,922
Other	1	6	(6)	-	-	(4)	-
Net cash provided by operating activities	$ (1,006)	$ 116	$ (362)	$ (623)	$ 3,302	$ 25,348	$ 1,885
Cash and cash equivalents as stated in the Combined Statements of Net Position							
Cash and cash equivalents - restricted	$ 1	$ 1	$ -	$ 1	$ 6	$ 6	$ -
Cash and cash equivalents - unrestricted	1,816	1,338	2,761	1,417	3,363	16,976	1,885
	$ 1,817	$ 1,339	$ 2,761	$ 1,418	$ 3,369	$ 16,982	$ 1,885

See accompanying notes.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINING STATEMENTS OF CASH FLOWS
FOR THE YEAR ENDED JUNE 30, 2014
(AMOUNTS IN THOUSANDS)

	POWER PURCHASE AGREEMENTS					
	Ormat Geothermal Energy	MWD Small Hydro	Pebble Springs	Ameresco Chiquita Landfill Gas	Don A. Campbell Wild Rose Geothermal	Copper Mountain Solar 3
Cash flows from operating activities						
Receipts from participants	$ 4,823	$ 2,094	$ 19,843	$ 2,446	$ 8,435	$ 1,618
Receipts from sale of oil and gas	-	-	-	-	-	-
Payments to operating managers	(7,395)	(2,868)	(23,438)	(2,689)	(8,368)	(3)
Other disbursements and receipts	-	-	-	-	-	-
Net cash flows from operating activities	(2,572)	(774)	(3,595)	(243)	67	1,615
Cash flows from noncapital financing activities						
Advances (withdrawals) by participants, net	-	-	-	-	-	-
Cash flows from capital financing activities						
Additions to plant and prepaid projects, net	-	-	-	-	-	-
Debt interest and swap payments	-	-	-	-	-	-
Proceeds from sale of bonds	-	-	-	-	-	-
Payment for defeasance of revenue bonds	-	-	-	-	-	-
Transfer of funds from (to) escrow	-	-	-	-	-	-
Transfer of funds from (to) Mine Reclamation Trust Fund	-	-	-	-	-	-
Transfer of funds from (to) other projects	-	-	-	-	-	-
Principal payments on debt	-	-	-	-	-	-
Payment for bond issue costs	-	-	-	-	-	-
Net cash used for capital and related financing activities	-	-	-	-	-	-
Cash flows from investing activities						
Interest received on investments	5	2	5	-	-	-
Purchases of investments	-	-	-	-	-	-
Proceeds from sale/maturity of investments	-	-	-	-	-	-
Net cash provided by (used for) investing activities	5	2	5	-	-	-
Net increase (decrease) in cash and cash equivalents	(2,567)	(772)	(3,590)	(243)	67	1,615
Cash and cash equivalents, beginning of year	5,386	1,993	7,713	2,284	-	-
Cash and cash equivalents, end of year	$ 2,819	$ 1,221	$ 4,123	$ 2,041	$ 67	$ 1,615
Reconciliation of operating income (loss) to net cash provided by operating activities						
Operating income (loss)	$ (6)	$ (2)	$ (5)	$ -	$ -	$ -
Adjustments to reconcile operating income (loss) to net cash provided by operating activities						
Depreciation, depletion and amortization	-	-	-	-	-	-
Decommissioning	-	-	-	-	-	-
Advances for capacity and energy	-	-	-	-	-	-
Amortization of nuclear fuel	-	-	-	-	-	-
Changes in assets and liabilities						
Accounts receivable	-	(170)	-	188	(915)	-
Accounts payable and accruals	(2,572)	(610)	(3,590)	(436)	982	1,615
Other	6	8	-	5	-	-
Net cash provided by operating activities	$ (2,572)	$ (774)	$ (3,595)	$ (243)	$ 67	$ 1,615
Cash and cash equivalents as stated in the Combined Statements of Net Position						
Cash and cash equivalents – restricted	$ -	$ -	$ -	$ -	$ -	$ -
Cash and cash equivalents – unrestricted	2,819	1,221	4,123	2,041	67	1,615
	$ 2,819	$ 1,221	$ 4,123	$ 2,041	$ 67	$ 1,615

See accompanying notes.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINING STATEMENTS OF CASH FLOWS
FOR THE YEAR ENDED JUNE 30, 2015
(AMOUNTS IN THOUSANDS)

	Project Development Fund	Projects' Stabilization Fund	SCPPA Fund	Total Combined
Cash flows from operating activities				
Receipts from participants	$ -	$ -	$ -	$ 700,656
Receipts from sale of oil and gas	-	-	-	16,286
Payments to operating managers	-	-	-	(350,001)
Other disbursements and receipts	-	-	(144)	17,376
Net cash flows from operating activities	-	-	(144)	384,317
Cash flows from noncapital financing activities				
Advances (withdrawals) by participants, net	6,420	2,857	144	1,590
Cash flows from capital financing activities				
Additions to plant and prepaid projects, net	-	-	(149)	(34,316)
Debt interest and swap payments	-	-	-	(143,210)
Proceeds from sale of bonds	-	-	-	316,095
Payment for defeasance of revenue bonds	-	-	-	(349,670)
Transfer of funds from (to) escrow	-	-	-	-
Transfer of funds from (to) Mine Reclamation Trust Fund	-	-	-	(420)
Transfer of funds from (to) other projects	-	-	-	-
Principal payments on debt	-	-	-	(122,520)
Payment for bond issue costs	-	-	-	(24,150)
Net cash used for capital and related financing activities	-	-	(149)	(358,191)
Cash flows from investing activities				
Interest received on investments	-	1,246	-	5,294
Purchases of investments	-	(102,385)	-	(425,834)
Proceeds from sale/maturity of investments	-	87,475	-	428,445
Net cash provided by (used for) investing activities	-	(13,664)	-	7,905
Net increase (decrease) in cash and cash equivalents	6,420	(10,807)	(149)	35,621
Cash and cash equivalents, beginning of year	65	20,826	314	301,753
Cash and cash equivalents, end of year	$ 6,485	$ 10,019	$ 165	$ 337,374
Reconciliation of operating income (loss) to net cash provided by operating activities				
Operating income (loss)	$ -	$ -	$ 19	$ 144,215
Adjustments to reconcile operating income (loss) to net cash provided by operating activities				
Depreciation, depletion and amortization	-	-	113	158,745
Decommissioning	-	-	-	10,857
Advances for capacity and energy	-	-	-	2,550
Amortization of nuclear fuel	-	-	-	14,493
Pension expense	-	-	(276)	(276)
Changes in assets and liabilities				
Accounts receivable	-	-	-	4,481
Accounts payable and accruals	-	-	-	33,764
Other	-	-	-	15,488
Net cash provided by operating activities	$ -	$ -	$ (144)	$ 384,317
Cash and cash equivalents as stated in the Combined Statements of Net Position				
Cash and cash equivalents - restricted	$ 6,485	$ 10,019	$ 165	$ 236,950
Cash and cash equivalents - unrestricted	-	-	-	100,424
	$ 6,485	$ 10,019	$ 165	$ 337,374

See accompanying notes.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINING STATEMENTS OF CASH FLOWS
FOR THE YEAR ENDED JUNE 30, 2014
(AMOUNTS IN THOUSANDS)

	MISCELLANEOUS				
	Multiple Project Fund	Project Development Fund	Projects' Stabilization Fund	SCPPA Fund	Total Combined
Cash flows from operating activities					
Receipts from participants	$ -	$ -	$ -	$ -	$ 621,802
Receipts from sale of oil and gas	-	-	-	-	9,152
Payments to operating managers	-	-	-	-	(296,029)
Other disbursements and receipts	-	-	-	(130)	21,897
Net cash flows from operating activities	-	-	-	(130)	356,822
Cash flows from noncapital financing activities					
Advances (withdrawals) by participants, net	-	(89)	21,692	470	25,708
Cash flows from capital financing activities					
Additions to plant and prepaid projects, net	-	-	-	(72)	(335,618)
Debt interest and swap payments	(466)	-	-	-	(145,419)
Proceeds from sale of bonds	-	-	-	-	333,872
Payment for defeasance of revenue bonds	-	-	-	-	-
Transfer of funds from (to) escrow	-	-	-	-	-
Transfer of funds from (to) Mine Reclamation Trust Fund	-	-	-	-	(489)
Transfer of funds from (to) other projects	(26,372)	-	-	-	(24,822)
Principal payments on debt	(13,800)	-	-	-	(189,730)
Payment for bond issue costs	-	-	-	-	(2,508)
Net cash used for capital and related financing activities	(40,638)	-	-	(72)	(364,714)
Cash flows from investing activities					
Interest received on investments	1,441	-	1,218	-	8,132
Purchases of investments	-	-	(73,197)	-	(436,386)
Proceeds from sale/maturity of investments	39,197	-	61,300	-	481,262
Net cash provided by (used for) investing activities	40,638	-	(10,679)	-	53,008
Net increase (decrease) in cash and cash equivalents	-	(89)	11,013	268	70,824
Cash and cash equivalents, beginning of year	-	154	9,813	46	230,929
Cash and cash equivalents, end of year	$ -	$ 65	$ 20,826	$ 314	$ 301,753
Reconciliation of operating income (loss) to net cash provided by operating activities					
Operating income (loss)	$ -	$ -	$ -	$ (243)	$ 137,637
Adjustments to reconcile operating income (loss) to net cash provided by operating activities					
Depreciation, depletion and amortization	-	-	-	113	149,779
Decommissioning	-	-	-	-	5,679
Advances for capacity and energy	-	-	-	-	3,031
Amortization of nuclear fuel	-	-	-	-	16,031
Changes in assets and liabilities					
Accounts receivable	-	-	-	-	(4,830)
Accounts payable and accruals	-	-	-	-	29,294
Other	-	-	-	-	20,201
Net cash provided by operating activities	$ -	$ -	$ -	$ (130)	$ 356,822
Cash and cash equivalents as stated in the Combined Statements of Net Position					
Cash and cash equivalents – restricted	$ -	$ 65	$ 20,826	$ 314	$ 205,018
Cash and cash equivalents – unrestricted	-	-	-	-	96,735
	$ -	$ 65	$ 20,826	$ 314	$ 301,753

See accompanying notes.

Note 1 – Organization and Purpose

The Southern California Public Power Authority (the Authority or SCPPA), a public entity organized under the laws of the State of California, was formed by a Joint Powers Agreement dated as of November 1, 1980 pursuant to the Joint Exercise of Powers Act of the State of California. The Authority's participants consist of eleven municipal electric utilities and one irrigation district in the State of California. The Authority was formed for the purpose of planning, financing, developing, acquiring, constructing, operating and maintaining projects for the generation, transmission, and procurement of electric energy and natural gas for sale to its participants. The Joint Powers Agreement has a term expiring in 2030 or such later date as all bonds and notes of the Authority and the interest thereon have been paid in full or adequate provision for payments have been made.

The Authority has interests in the following projects:

GENERATION PROJECTS

Palo Verde Project – On August 14, 1981, the Authority purchased a 5.91% interest in the Palo Verde Nuclear Generating Station (PVNGS), a 3,810 MW nuclear-fueled generating station near Phoenix, Arizona, a 5.44% ownership interest in the Arizona Nuclear Power Project High Voltage Switchyard (ANPP HVS), and a 6.55% share of the right to use certain portions of the Arizona Nuclear Power Project Valley Transmission System (collectively, the Palo Verde Project). Units 1, 2 and 3 of the Palo Verde Project began commercial operations in January 1986, September 1986, and January 1988, respectively.

Since inception of the ANPP HVS capital additions, new terminations, and other events have successively changed the respective ownership interests in the ANPP HVS. In FYE 2011, the PVNGS fourth transformer became the 14th termination in the ANPP HVS, and caused the Authority's proportional ownership percentage to change from 5.56% to 5.44%. This change became effective on April 1, 2011.

Units 1, 2, and 3 each operated under a 40-year Full-Power Operating License from the Nuclear Regulatory Commission (NRC), expiring in 2025, 2026, and 2027, respectively. In April 2011, after a detailed, two-year process, the NRC approved the application to extend the operating licenses for all three units for an additional 20 years, allowing Unit 1 to operate through 2045, Unit 2 through 2046, and Unit 3 through 2047.

San Juan Project – Effective July 1, 1993, the Authority purchased a 41.80% interest in Unit 3 and related common facilities of the San Juan Generating Station (SJGS) from Century Power Corporation. Unit 3, a 497-MW unit, is one unit of a four-unit coal-fired power generating station in New Mexico.

Note 1 – Organization and Purpose (continued)

Magnolia Power Project – The Magnolia Power Project (MAG) consists of a combined cycle natural gas-fired generating plant with a nominally rated net base capacity of 242 MW and was built on a site in Burbank, California. The plant is the first that is wholly owned by the Authority and entitlements to 100% of the capacity and energy of the Project have been sold to six of its members.

The City of Burbank, a Project participant, managed its construction and also serves as the operating agent for the Project. Commercial operations began on September 22, 2005.

- **Gas Supply and Services Agreement** – SCPPA entered into an agreement with Occidental Energy Marketing, Inc. (OEMI) beginning January 2005. This agreement is renewed each year unless notification is given by either party prior to December 31, of each year. OEMI provides 100% of the natural gas plant requirements on a daily basis, and also includes an option for the participants to bring in their own gas supply. In addition, OEMI provides gas balancing services.

- **Natural Gas Transportation** – SCPPA has an agreement with Southern California Gas Company (SoGas) for intrastate transmission services. The agreement took effect in January 2005 and the contract term was renewed in February 2013 and will continue for three additional years thereafter unless canceled by the Authority prior to February 1 of each year. SoGas provides transportation, storage, and balancing services of natural gas from the Southern California Border to the Magnolia Plant.

- **Parts and Special Services Agreement** – SCPPA entered into an 18-year agreement with General Electric International (GE) in September 2005. Initially, the agreement covered only the gas turbine, but the agreement was amended in August 2007, to include coverage for the gas generator, the steam turbine, and the steam generator. GE provides planned and unplanned maintenance, including replacement parts, based on factored fired hours.

Canyon Power Project – The Canyon Power Project (the Project) consists of a simple cycle natural gas-fired power generating plant, comprised of four combustion turbines with a combined nominally rated net base capacity of 200 MW, and auxiliary facilities, located in an industrial area of the city of Anaheim, California (Anaheim). The Project is owned by the Authority and constructed, operated, and maintained by Anaheim. The Project achieved full commercial operation in September 2011.

Note 1 - Organization and Purpose (continued)

Apex Power Project - On March 26, 2014, the Authority acquired the Apex Power Project (the Project) pursuant to an Asset Purchase Agreement, dated as of October 17, 2013. The Project consists of a natural gas-fired, combined cycle generating facility (the "Facility"), nominally-rated at 531 MW, located in Clark County, Nevada, generator interconnection facilities, related assets and property, and interconnection and transmission contractual rights. The Facility is interconnected through a 3.13 mile 500 kV radial generation tie line owned by Nevada Power Company that connects the Facility to the Nevada Power Company's transmission system at its Harry Allen 500 kV Substation. The Los Angeles Department of Water & Power (LADWP) serves as project manager of the Project.

- **Operation and Maintenance Agreement** - The Facility is operated by EthosEnergy Power Operations (West), LLC (EthosEnergy), formerly Wood Group Power Operations (West), Inc., pursuant to an Operations and Maintenance Agreement dated February 12, 2007. Under the O&M Agreement, EthosEnergy provides all operations, routine maintenance, budget control, purchasing, billing, and reporting for the operation of the Facility, other than the maintenance provided by General Electric International ("GEI"), under a long-term service agreement. EthosEnergy currently employs 22 people at the Facility for operation and maintenance purposes. The O&M Agreement initially between the Seller and EthosEnergy was assumed and amended by the Authority. The term of the O&M Agreement, which expires on February 12, 2016, has been extended to February 12, 2017.

- **Large Generator Interconnection Agreement (LGIA)** - The LGIA between Nevada Power Company and the Seller, dated July 1, 2001, provides for the interconnection of the Facility, and firm transmission service for the Facility output through two Service Agreements for Long-Term Point-to-Point Transmission Service, dated April 22, 2008 (together the "TSA"), with a point of delivery at the Mead 240 kV Substation. The term of these two agreements extends to July 30, 2023. The Authority expects to extend the term or renew these agreements prior to their expiration date or to provide for alternative transmission service from the Facility to the Mead 230 kV Substation. The Seller's obligations, under the Asset Purchase Agreement, is secured by a letter of credit in the amount of $10,000,000 which expires 18 months after the acquisition date of the Facility by the Authority and by a guaranty provided by a limited liability company for a period of 5 years following the acquisition.

- **Long-Term Service Agreement** - Major maintenance, including parts supply, parts repair and labor for the Facility's combustion turbine generators and the steam turbine are provided pursuant to a Long-Term Service Agreement ("LTSA") between the Seller and GEI, dated June 16, 2004. It is not currently possible to determine when the LTSA will expire, but the Authority anticipates that it will not expire prior to six years after the Facility acquisition date.

Note 1 – Organization and Purpose (continued)

- **Operational Balancing Authority Agreement and Letter Agreement** – The natural gas to fuel the Facility will be provided by LADWP and delivered by facilities owned by the Kern River Gas Transmission Company through an Operational Balancing Authority Agreement and Letter Agreement.

- **Water Agreement** – Water for the facility will be provided by Las Vegas Valley Water District pursuant to an agreement, dated June 5, 2001 and assigned to the Authority upon acquisition of the Facility. Unless extended, the Water Agreement expires on June 5, 2038.

- **Transmission Service Agreements (TSAs)** – Under the TSAs, Nevada Power Company currently provides transmission services to deliver the output of the Facility to the Mead 230 kV Substation. The rates, terms and conditions for such services are regulated by the Federal Energy Regulatory Commission pursuant to Nevada Power Company's open access transmission tariff. Changes to the rates are not accurately predictable and subject to numerous factors unrelated to the Apex Project.

LADWP, as the Project Manager, will administer, supervise, monitor and enforce the O&M Agreement and the LTSA in accordance with the Agency Agreement.

GREEN POWER

Hoover Uprating Project – As of March 1, 1986, the Authority and six participants entered into an agreement pursuant to which each participant assigned its entitlement to Hoover Uprating capacity and associated firm energy to the Authority in return for the Authority's agreement to provide for the advancement of funds for the uprating to the United States Bureau of Reclamation (USBR) on behalf of such participants. The agreement expires on September 30, 2017.

On December 20, 2011, the Hoover Power Allocation Act, which extends the availability of Hoover Power to the existing contractors for an additional fifty years and creates a pool for new entrants, was signed into law. The participants will enter into new agreements with the federal government for the capacity and energy, effective from October 1, 2017 through September 30, 2067. Whether the Authority will play a role in the project after 2017 cannot be determined at this time.

Tieton Hydropower Project – On November 30, 2009, the Authority acquired the Tieton Hydropower Plant pursuant to an Asset Purchase Agreement, dated as of October 19, 2009. The Tieton Hydropower Project (the Project) consists of a 13.6 MW nameplate capacity "run-of-the-reservoir" hydroelectric generation facility, comprised of: a powerhouse located in Yakima County, Washington; a 21-mile 115 kV transmission line; other related assets, property, and contractual rights.

Note 1 - Organization and Purpose (continued)

- **Contractor Service Agreement** - SCPPA entered into an agreement with Emanuel Services (Contractor) on January 1, 2013 to direct the operations of the Tieton Hydropower facility and to provide certain technical services with respect to the operation and maintenance of the facility. The term of the contract is for one year and was extended to June 30, 2014. On July 1, 2014 a new contract went into effect with Energy Northwest for a term of one year and it may be extended for a period of one month to one year upon mutual agreement of the parties.

- **Facilities Maintenance Agreement** - SCPPA entered into an agreement with PacifiCorp to provide supervision, labor, materials, and equipment necessary to perform routine non-emergency maintenance of the facilities and routine vegetation management. The agreement started on April 28, 2010 and will continue for as long as the Interconnection agreement is in effect, unless terminated by mutual agreement.

- **Small Generator Interconnection Agreement** - SCPPA entered into an agreement with PacifiCorp to perform certain interconnection requests submitted under the Small Generator Interconnection Procedures. This agreement governs the terms and conditions under which SCPPA's Small Generating Facility will interconnect with PacifiCorp's Transmission System. The agreement became effective on November 30, 2009 and will remain in effect for a period of 10 years after which it will automatically renew for successive one-year periods, unless terminated by a 20-day written notice in accordance with this agreement.

Milford I Wind Project - On February 9, 2010, the Authority financed the prepayment of a specified supply of electricity from a wind farm located in Milford, Utah (the Facility). The Facility is a 203.5 MW nameplate capacity wind farm comprised of 97 wind turbines located near Milford, Utah, together with a 90-mile transmission line, and other related facilities. Under the related power purchase agreements by and between SCPPA and Milford Wind Corridor Phase I, LLC (the Seller), SCPPA will receive 6.7 million MW hours over a 20-year delivery term. SCPPA has also agreed to make monthly payments to the Seller for any energy delivered in each year that exceeds the guaranteed annual quantity of 338,215 MW hours. Commercial operation began on November 16, 2009.

Milford II Wind Energy Project - On August 25, 2011, the Authority financed the prepayment of a specified supply of energy from the Milford Wind Corridor Phase II Project (the Milford II Project), for a delivery term of 20 years (unless terminated earlier) pursuant to a Power Purchase Agreement dated March 1, 2010. The Authority also entered into power sales agreements with LADWP and the city of Glendale (Glendale) to sell 100% of its entitlement to capacity and energy in the Facility on a "take-or-pay basis." Under a separate contract, the city of Glendale sold its entitlement share of energy to LADWP until Glendale exercises its option to repurchase its share. The Facility is a 102 MW nameplate capacity wind powered electric generating facility comprised of 68 1.5 MW wind turbines and related facilities located near Milford, Utah. The Milford II Project achieved commercial operation on May 2, 2011.

Note 1 – Organization and Purpose (continued)

Linden Wind Energy Project – On September 15, 2010, the Authority acquired the Linden Wind Energy Project (the Project) pursuant to the terms of the Asset Purchase Agreement, dated as of June 23, 2009. The Project is an approximately 50 MW nameplate capacity wind farm comprised of 25 wind turbines and related facilities, located in Klickitat County, Washington, developed and constructed by Northwest Wind Partners, LLC. The Authority has also entered into power sales agreements with LADWP and Glendale to sell 100% of its entitlement to capacity and energy in the Project on a "take-or-pay" basis. Through a separate layoff agreement, the City of Glendale has sold 100% of its entitlement to capacity and energy to LADWP, but remains responsible for all payments associated with its participation in the power sales agreement if LADWP fails to buy the energy pursuant to the layoff agreement.

- **Operation and Maintenance Service Agreement** – SCPPA entered into a three-year agreement with Senvion Wind Energy Solutions ("Senvion") (formally, REpower Systems AG) in February 2012. This agreement automatically renews for an additional two years unless either party provides written notice to the other party to cancel the contract. Senvion performs fixed fee services such as scheduled maintenances, periodic operational checks and tests, and regular preventive maintenance required on the wind turbine generators (WEC) in accordance with the maintenance manual. Senvion also performs remote monitoring services, repair services, and services related to the availability of the WEC. The agreement with Senvion remains in effect as of June 30, 2015.

- **Energy Exchange Agreement** – SCPPA entered into a two-year agreement with Powerex Corp. on November 27, 2012 for delivery of energy to Powerex for shaping and moving services. The delivery term may be renewed for up to five additional one-year terms commencing on January 1 of each successive calendar year, if the parties have confirmed in writing their agreement to extend this contract not less than ninety days prior to the commencement of each renewal term. The agreement with Powerex remains in effect as of June 30, 2015.

- **Balance of Plant Agreement** – Cannon Power Services Company, LLC assumed responsibility for operations of the Linden Wind Energy Project from EDF Renewable Energy (formerly EnXco Service Corporation) through an agreement with SCPPA that was executed on July 9, 2013 and was effective September 3, 2013. This agreement to operate, maintain, and repair the Wind Plant will continue for a period of three years and will automatically be extended for successive one year periods unless either party provides written notice to terminate the contract. The agreement with Cannon Power Services Company, LLC remains in effect as of June 30, 2015.

Note 1 – Organization and Purpose (continued)

Windy Point/Windy Flats Project – On September 9, 2010, the Authority financed the purchase of a supply of energy from the Windy Point/Windy Flats Project (the Project) for an initial delivery term of 20 years, pursuant to the terms of a power purchase agreement, dated June 24, 2009. The Authority also entered into power sales agreements with LADWP and the city of Glendale to sell 100% of its entitlement to capacity and energy in the Project on a "take-or-pay" basis. Through a separate layoff agreement, the City of Glendale sold 100% of its entitlement to capacity and energy to LADWP, but remains responsible for all payments associated with its participation in the power sales agreement if LADWP fails to buy the energy pursuant to the layoff agreement.

The Project is a facility with a 262.2 MW nameplate capacity wind farm comprised of 114 wind turbines located in the Columbia Hills area of Klickitat County, Washington near the city of Goldendale. The Project is owned by Windy Flats Partners, LLC, a limited liability company organized and existing under the laws of the State of Delaware. The initial delivery term began on the commercial operation date of the first of two phases of the facility. The first phase commenced operations on January 25, 2010 and the second phase on March 1, 2010.

TRANSMISSION PROJECTS

Southern Transmission System Project – On May 1, 1983, the Authority entered into an agreement with the Intermountain Power Agency (IPA), to defray all the costs of acquisition and construction of the Southern Transmission System Project (STS), which provides for the transmission of energy between the Southern California and the Rocky Mountain regional markets, including long-term renewable resources such as Milford I Wind and Milford II Wind, from the Intermountain Generating Station located in Utah to Southern California. STS commenced commercial operations in July 1986. Construction to upgrade two AC/DC converter stations and increase their combined rating from 1,920 MW to 2,400 MW was completed in May 2011. The LADWP, a member of the Authority, serves as project manager and operating agent of the Intermountain Power Project (IPP).

Mead-Phoenix and Mead-Adelanto Projects – As of August 4, 1992, the Authority entered into an agreement to acquire an interest in the Mead-Phoenix Project (Mead-Phoenix), a transmission line extending between the Westwing substation in Arizona and the Marketplace substation in Nevada. The agreement provides the Authority with an 18.31% interest in the Westwing-Mead project component, a 17.76% interest in the Mead Substation project component, and a 22.41% interest in the Mead-Marketplace project component.

As of August 4, 1992, the Authority also entered into an agreement to acquire a 67.92% interest in the Mead-Adelanto Project (Mead-Adelanto), a transmission line extending between the Adelanto substation in Southern California and the Marketplace substation in Nevada. Funding for these projects was provided by a transfer of funds from the Multiple Project Fund and commercial operations commenced in April 1996. LADWP serves as project manager and operating agent of Mead-Adelanto.

Note 1 - Organization and Purpose (continued)

NATURAL GAS PROJECTS

Pinedale Project - On July 1, 2005, the Authority, together with LADWP and Turlock Irrigation District (TID), acquired 42.5% of an undivided working interest in three natural gas leases located in the Pinedale Anticline region of the State of Wyoming. The Authority's individual share in these interests equals 14.9%. The purchase includes 38 operating oil and gas wells and associated lateral pipelines, equipment, permits, rights of way, and easements used in production. The natural gas field production is expected to increase for several more years as additional capital is invested on drilling new wells and then decline over a life expectancy greater than 30 years.

- **Joint Operating Agreement (JOA)** - In July 2005, SCPPA's purchase of the natural gas reserve interests at Pinedale, Wyoming (Pinedale) included an underlying long-term JOA with the operator, Ultra Resources, Inc. SCPPA pays the operator for SCPPA's share of both operating and drilling/capital expenses on a monthly basis.

- **Gathering and processing agreements** - SCPPA's purchase of Pinedale included underlying agreements with Jonah Gas Gathering Company, Questar Gas Management Company, and Western Gas Resources, Inc. for gathering and processing of the natural gas.

Barnett Project - Natural gas resources in the Barnett shale geological formation in Texas were acquired from Collins and Young Holding, L.L.P (C&Y) for a total of $84 million. The acquisition settled on October 26, 2006 and was completed on December 7, 2006 when the participants, together with TID, exercised their option to purchase additional resources from C&Y.

- **Joint Operating Agreement (JOA)** - In October 2006, SCPPA's purchase of the natural gas reserve interests in Barnett, TX (Barnett) included an underlying long-term JOA with the operator, Devon Energy Production Company, L.P. SCPPA pays the operator for SCPPA's share of both operating and drilling/capital expenses on a monthly basis.

Prepaid Natural Gas Project - On October 11, 2007, the Authority made a one-time prepayment of $481 million to acquire the right to receive approximately 135 billion cubic feet of natural gas from J. Aron & Company (J. Aron) to be delivered over a 30-year term, beginning July 1, 2008. On October 3, 2007, prior to the acquisition of the prepaid gas supply, the Authority entered into five separate Prepaid Natural Gas Sales Agreements (the Gas Sales Agreements) with J. Aron and simultaneously, five Prepaid Natural Gas Supply Agreements (the Gas Supply Contracts) in which the Authority sold its interest in the natural gas, on a "take-and-pay" basis, to the cities of Anaheim, Burbank, Colton, Glendale, and Pasadena (the Project Participants). Through the Gas Supply Contracts, SCPPA has provided for the sale to the Project Participants, on a pay-as-you-go basis, of all of the natural gas to be delivered to SCPPA pursuant to the Gas Sales Agreements.

Note 1 - Organization and Purpose (continued)

- On October 22, 2009, the Prepaid Natural Gas Sales Agreements and certain other agreements were restructured to reduce risk, provide an acceleration of a portion of the long-term savings, reduce the remaining volumes of gas to be delivered from 135 billion to 90 billion cubic feet, and shorten the term of the agreements from 30 years to 27 years. As a result of the restructuring, the Natural Gas contracts will now expire in 2035 and $165.5 million principal of the 2007 Natural Gas Project Bonds were terminated (see Note 6).

- Under the Gas Supply Contracts, the approximate average Daily Quantity of gas to be purchased by each Project Participant is as follows:

	Average Daily Quantity (1)		
Project Participant	Revised Volumes	Original Volumes	Participant Percentage (%)
City of Anaheim	1,467	2,000	16.5%
City of Burbank	2,924	4,000	33.0%
City of Colton	1,007	1,375	11.0%
City of Glendale	2,015	2,750	23.0%
City of Pasadena	1,464	2,000	16.5%
Total	8,877	12,125	100.0%

(1) The Average Daily Quantity is in MMBtu and is calculated over the term of the applicable Gas Supply Contracts. The contracts were restructured and volumes revised in October 2009.

Note 1 – Organization and Purpose (continued)

Participant ownership interests – The Authority's participants may elect to participate in the projects. As of June 30, 2015, the members have the following participation percentages in the Authority's operating projects:

	GENERATION					TRANSMISSION		
Participants	Palo Verde Project	San Juan Project	Magnolia Power Project	Canyon Power Project	Apex Power Project	Southern Transmission System	Mead-Phoenix Project	Mead-Adelanto Project
City of Los Angeles	67.0%	-	-	-	100.0%	59.5%	24.8%	35.7%
City of Anaheim	-	-	38.0%	100%	-	17.6%	24.2%	13.5%
City of Riverside	5.4%	-	-	-	-	10.2%	4.0%	13.5%
Imperial Irrigation District	6.5%	51.0%	-	-	-	-	-	-
City of Vernon	4.9%	-	-	-	-	-	-	-
City of Azusa	1.0%	14.7%	-	-	-	-	1.0%	2.2%
City of Banning	1.0%	9.8%	-	-	-	-	1.0%	1.3%
City of Colton	1.0%	14.7%	4.2%	-	-	-	1.0%	2.6%
City of Burbank	4.4%	-	31.0%	-	-	4.5%	15.4%	11.5%
City of Glendale	4.4%	9.8%	16.5%	-	-	2.3%	14.8%	11.1%
City of Cerritos	-	-	4.2%	-	-	-	-	-
City of Pasadena	4.4%	-	6.1%	-	-	5.9%	13.8%	8.6%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

	GREEN POWER						NATURAL GAS		
Participants	Hoover Uprating Project	Tieton Hydro-power	Milford I Wind	Milford II Wind	Linden Wind Energy	Windy Point Project	Pinedale Project	Barnett Project	Prepaid Natural Gas Project
City of Los Angeles	-	-	92.5%	95.1%	90.0%	92.4%	-	-	-
City of Anaheim	42.6%	-	-	-	-	-	35.7%	45.4%	16.5%
City of Riverside	31.9%	-	-	-	-	-	-	-	-
Imperial Irrigation District	-	-	-	-	-	-	-	-	-
City of Vernon	-	-	-	-	-	-	-	-	-
City of Azusa	4.2%	-	-	-	-	-	-	-	-
City of Banning	2.1%	-	-	-	-	-	-	-	-
City of Colton	3.2%	-	-	-	-	-	7.1%	9.1%	11.0%
City of Burbank	16.0%	50.0%	5.0%	-	-	-	14.3%	27.3%	33.0%
City of Glendale	-	50.0%	-	4.9%	10.0%	7.6%	28.6%	-	23.0%
City of Cerritos	-	-	-	-	-	-	-	-	-
City of Pasadena	-	-	2.5%	-	-	-	14.3%	18.2%	16.5%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

The Authority has entered into power sales, natural gas sales, and transmission service agreements with the above project participants. Under the terms of the contracts, the participants are entitled to power output, natural gas, or transmission service, as applicable. The participants are obligated to make payments on a "take-or-pay" basis for their proportionate share of operating and maintenance expenses and debt service. The contracts cannot be terminated or amended in any manner that will impair or adversely affect the rights of the bondholders as long as any bonds issued by the specific project remain outstanding.

Note 1 – Organization and Purpose (continued)

The contracts expire as follows:

Palo Verde Project	2030
San Juan Project	2030
Magnolia Power Project	2036
Canyon Power Project	2040
Apex Power Project	2038
Hoover Uprating Project	2018
Tieton Hydropower Project	2040
Milford I Wind Project	2030
Milford II Wind Project	2031
Linden Wind Energy Project	2035
Windy Point Project	2030
Southern Transmission System Project	2027
Mead-Phoenix Project	2030
Mead-Adelanto Project	2030
Natural Gas Pinedale Project	2040
Natural Gas Barnett Project	2040
Prepaid Natural Gas Project	2038
Ormat Geothermal Energy Project	2031
Pebble Springs Wind Project	2025
MWD Small Hydro Project	2023
Ameresco Chiquita Landfill Gas Project	2030
Don A Campbell Wild Rose Project	2033
Copper Mountain Solar 3 Project	2040
Columbia Solar 2 Project	2033

The Authority's interests or entitlements in natural gas, generation, and transmission projects are jointly owned with other utilities, except for the Magnolia Power Project, Canyon Power Project, Apex Power Project, Tieton Hydropower Project, and the Linden Wind Energy Project, which are wholly owned by the Authority. Under these arrangements, a participating member has an undivided interest in a utility plant and is responsible for its proportionate share of the costs of construction and operation and is entitled to its proportionate share of the energy, available transmission capacity, or natural gas produced. Each joint plant participant, including the Authority, is responsible for financing its share of construction and operating costs. The financial statements reflect the Authority's interest in each jointly owned project as well as the projects that it owns. Additionally, the Authority's share of expenses for each project is included in the statements of revenues, expenses, and changes in net position as part of operations and maintenance expenses.

Note 1 – Organization and Purpose (continued)

POWER PURCHASE AGREEMENTS

Ormat Geothermal Energy Project – The Authority entered into long-term power purchase agreements in December 2005 with divisions of Ormat Technologies, Inc. for up to 20 MW of electric generation. The Project started delivery of approximately 5 MW in January 2006 from geothermal energy facilities located in Heber, California and the agreements were amended to allow for excess capacity in May 2008. The city of Anaheim acts as the scheduling coordinator on behalf of the project participants. The term of the contract is 25 years.

MWD Small Hydro Project – Consists of a power purchase agreement for the output from four small hydroelectric plants on the MWD system in Southern California, having a total nameplate capacity of 17.04 MW, and a historical output of 40,130 MWH per year. Transmission is accomplished through the California Independent System Operator, with the city of Anaheim acting as scheduler. The term of the contract is 15 years and 2 months, expiring December 31, 2023. Operations began on November 1, 2008.

Pebble Springs Wind Project – In December 2007, the Authority entered into a power purchase agreement for the facility output of a wind project with 98.7 MW, located in Gilliam County, Oregon. SCPPA along with LADWP, Burbank, and Glendale are now scheduling the energy through transmission agreements which bring this renewable energy from the project substation to the project participants. The term of the Project is 18 years with a right of first offer to potentially purchase the entire project after the 10th contract year. Operations formally began on January 31, 2009.

Ameresco Chiquita Energy Project – In March 2004, SCPPA entered into a power purchase agreement with Ameresco Chiquita Energy LLC, subsequently amended in September 2006, for 100% of the electric generation from a landfill gas to energy facility located at the landfill site in Valencia, California (Ameresco Landfill Gas to Energy Project). The SCPPA participants in the project include the cities of Burbank and Pasadena. This project will initially be for 10 MW with the right of first refusal on any increase in output. Operations began in November 2010. The term of the contract is 20 years from the commercial operation date.

Don A. Campbell/Wild Rose Geothermal Energy Project – On December 31, 2012 the Authority entered into a power purchase agreement with Ormat Nevada, Inc. to purchase renewable geothermal energy from the Don A. Campbell/Wild Rose Facility (the "Facility") beginning December 31, 2013, for a 20-year term. The Facility is a geothermal power generating facility with a 16.2 MW nameplate capacity and a 95 percent capacity factor located in Mineral County, Nevada. The commercial operating date was December 31, 2013 but early delivery of energy began in November 2013. The two participants are LADWP and the city of Burbank. LADWP acts as project manager and has balancing authority at the point of delivery of energy at the Mead 230kV Substation in Southern Nevada. Electricity from the Project will be transmitted through Nevada Energy's transmission system that includes the new 500 kV One Nevada Transmission Line.

Note 1 – Organization and Purpose (continued)

Copper Mountain Solar 3 Project – On August 31, 2012, SCPPA entered into a power purchase agreement with Copper Mountain Solar 3, LLC to purchase certain renewable energy and associated environmental attributes. The Project's capacity is 250 MW.

Columbia Solar 2 Project – On September 19, 2013, SCPPA entered into a power purchase agreement with RE Columbia Two, LLC to purchase all of the output of the Columbia Solar 2 Project, and to acquire other rights and resources, including but not limited to the purchase option and the rights under other ancillary agreements associated with the project. The project, when fully developed, is contemplated to entail a photovoltaic solar power generating facility located in Kern County, California with an expected nameplate capacity of 15 MW. Commercial operation began on December 20, 2014. The term of the contract is 20 years. The City of Riverside is the scheduling coordinator on behalf of the participants.

The Authority has entered into power purchase agreements with project participants as follows. These agreements are substantially "take-and-pay" contracts where there may be other obligations not associated with the delivery of energy.

Participant Ownership Interests

	Power Purchase Agreements						
Participants	Ormat Geothermal Energy Project	Pebble Springs Wind Project	MWD Small Hydro Project	Ameresco Chiquita Landfill Gas Project	Campbell Wild Rose Geothermal Project	Copper Mountain Solar 3 Project	Columbia Solar 2 Project
Capacity	17.00 MW	98.70 MW	17.04 MW	10.00 MW	16.00 MW	250.00 MW	15.00 MW
City of Los Angeles	-	69.6%	-	-	84.6%	84.0%	-
City of Anaheim	60.0%	-	56.4%	-	-	-	-
City of Riverside	-	-	-	-	-	-	74.3%
City of Azusa	-	-	21.8%	-	-	-	8.6%
City of Banning	10.0%	-	-	-	-	-	-
City of Colton	-	-	21.8%	-	-	-	-
City of Burbank	-	10.1%	-	16.7%	15.4%	16.0%	-
City of Glendale	15.0%	20.3%	-	-	-	-	-
City of Pasadena	15.0%	-	-	83.3%	-	-	17.1%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Contract expires	2031	2025	2023	2030	2033	2040	2033

MISCELLANEOUS FUNDS

Multiple Project Fund – During fiscal year 1990, the Authority issued Multiple Project Revenue Bonds for net proceeds of approximately $600 million to provide funds to finance costs of construction and acquisition of ownership interests or capacity rights in one or more, then unspecified, projects for the generation or transmission of electric energy.

Note 1 – Organization and Purpose (continued)

Certain amounts of these funds were used to finance the Authority's interests in Mead-Phoenix and Mead-Adelanto. Final maturity of the 1989 Multiple Project Bonds occurred on July 1, 2013 leaving a Surplus Amount of approximately $6.4 million and $18.4 million available to the SCPPA Mead-Phoenix (MP) and Mead-Adelanto (MA) project participants, respectively. The Surplus Amount is the result of the savings obtained from the partial refunding within five years of the original issue of the 1989 Multiple Project Bonds by the MP and MA 1994 Series A Project Bonds. The partial refunding triggered a recalculation of the arbitrage yield, resulting in a higher arbitrage yield which reduced the rebate liability of the Authority and resulted in additional savings over the remaining life of the 1989 Multiple Project Bonds. At the time of the refunding, the Authority determined that these Surplus Amounts benefited and should be transferred to the MP and MA Project Participants after final maturity of the 1989 Multiple Project Bonds. The Multiple Project Fund was closed after the transfer was completed during the year ended June 30, 2014.

Project Development Fund – Holds funds related to projects in the development phase.

Projects' Stabilization Fund – In fiscal year 1997, the Authority authorized the creation of a Projects' Stabilization Fund. Deposits may be made into the fund from budget under-runs, after authorization of individual participants, and by direct contributions from the participants. Participants have discretion over the use of their deposits within SCPPA project purposes. This fund is not a project-related fund; therefore, it is not governed by any project Indenture of Trust. The members participate in the Projects' Stabilization Fund by making deposits to the fund at their discretion.

SCPPA Fund – In June 2011, the Authority acquired an 11,500 sq. ft. building located in the City of Glendora to be used as SCPPA office facilities. Acquisition and construction costs were financed by contributions from SCPPA members and the building was put into service during fiscal year 2012. All costs associated with the management, administration, and ongoing operations of the SCPPA Office Building are deemed to be SCPPA overhead costs and will be budgeted and paid in accordance with the projects annual budgets pursuant to SCPPA's traditional budgetary process. On July 18, 2013, the SCPPA Board authorized the installation of Solar Voltaic Equipment and Carports at the SCPPA Glendora Office Building. The estimated cost was financed by the SCPPA Members in accordance with their ownership interests in the SCPPA Building. (See Note 3).

In June 2012, the GASB issued Statement No. 68, *Accounting and Financial Reporting for Pensions*. This statement provides guidance for accounting for net pension liabilities, including definition of balances to be included in deferred inflows and deferred outflows of resources. The specific accounts impacting the Authority are included within the SCPPA Fund and are detailed in Note 10.

Note 2 – Summary of Significant Accounting Policies

Basis of accounting and presentation – The combined and individual financial statements of the Authority are prepared under the accrual basis of accounting in accordance with accounting principles generally accepted in the United States of America issued by the Governmental Accounting Standards Board (GASB) applicable to governmental entities that use proprietary fund accounting. Revenues are recognized when earned and expenses are recognized when incurred. The format of the Statement of Net Position follows the inverted approach which is consistent with the Federal Energy Regulatory Commission (FERC).

Change in accounting principal – In June 2012, the GASB issued Statement No. 68, *Accounting and Financial Reporting for Pensions*, effective for financial statement periods beginning after June 15, 2014. This statement provides guidance for accounting for net pension liabilities, including definition of balances to be included in deferred inflows and deferred outflows of resources. The Authority adopted this guidance as of and for the year ended June 30, 2015. The specific accounts impacting the Authority are included within the SCPPA Fund and are detailed in Note 10. The Authority has not restated the financial statements as of and for the year ended June 30, 2014 given that the necessary information was not made available by the California Public Employees' Retirement System pension plans.

Net position: The Authority's net position is classified as follows:

- **Net investment in capital assets** – This component of net position consists of capital assets, net of accumulated depreciation, reduced by the outstanding balances of any bonds, other borrowings, and advances from participants that are attributable to the acquisition, construction, or improvement of those assets. If there are significant unspent related debt proceeds at year-end, the portion of the debt attributable to the unspent proceeds is not included in the calculation of net investment in capital assets. Rather, that portion of the debt is included in the same net position component as the unspent proceeds.

- **Restricted** – This component consists of net position on which constraints are placed as to their use. Constraints include those 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 of net position consists of net position that does not meet the definition of "restricted" or "net investment in capital assets."

Use of estimates – The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the combined financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Note 2 – Summary of Significant Accounting Policies (continued)

Utility plant – The Authority's share of construction and betterment costs, natural gas reserves, intangibles, and nuclear fuel associated with PVNGS, STS, Mead-Phoenix, Mead-Adelanto, SJGS, Magnolia Power Project, the Natural Gas Pinedale Project and the Natural Gas Barnett Project (together the Natural Gas Projects) Canyon Power, Tieton Hydropower, Linden Wind Energy, and the Apex Power Projects are included as utility plant and recorded at cost. Utility plant also includes the SCPPA Building. Costs include labor, materials, capitalized interest costs on funds used in construction, and allocated indirect charges such as engineering, supervision, transportation and construction equipment, retirement plan contributions, health care costs, and certain administrative and general expenses. The costs of routine maintenance, repairs, and minor replacements incurred to maintain the plant in operating condition are charged to the appropriate operations and maintenance expense accounts in the period incurred. The original cost of property retired, net of removal and salvage costs, is charged to accumulated depreciation.

Depreciation expense is computed using the straight-line method based on the estimated service lives, principally 55 years for PVNGS, STS, Mead-Phoenix and Mead-Adelanto; 30 years for Magnolia and Canyon Power Project; 37 years for SJGS; 50 years for the Tieton Hydropower Project; 25 years for Linden Wind Energy Project; 24 Years for the Apex Power Project; and 35 years for the SCPPA Building Fund.

Natural gas reserve depletion – Depletion expense for the Natural Gas Projects is computed using the unit of production method based on the future production of the proven producing wells, estimated at 50 years for the Natural Gas Pinedale Project and 50 years for the Natural Gas Barnett Project. The estimate is based on site specific studies prepared by independent consultants as of December 2014 for both projects. The depletion rate for the Natural Gas Pinedale Project was $3.68/MMBtu and $3.35/MMBtu; and the estimated total net revenue volume was 11,598,794 MMBtu and 15,251,000 MMBtu, for fiscal years 2015 and 2014, respectively. The depletion rate for the Natural Gas Barnett Project was $4.83/MMBtu and $3.47/MMBtu; and the estimated total net revenue volume was 10,441,378 MMBtu and 15,518,375 MMBtu, for fiscal years ended June 30, 2015 and 2014, respectively.

Nuclear fuel – Nuclear fuel is amortized and charged to expense on the basis of actual thermal energy produced relative to total thermal energy expected to be produced over the life of the fuel. Under the provisions of the Nuclear Waste Policy Act of 1982, the federal government assesses each entity with nuclear operations, including the participants in PVNGS, $1 per MW hour of nuclear generation. The Authority records this charge as a current year expense. See Note 11 for information about spent nuclear fuel disposal.

Note 2 – Summary of Significant Accounting Policies (continued)

Nuclear decommissioning – Decommissioning of PVNGS is expected to commence subsequent to the year 2046. The total cost to decommission the Authority's interest in PVNGS is estimated to be $142.4 million in 2014 dollars ($730.4 million in 2042 dollars). This estimate is based on an updated site specific study prepared by an independent consultant in 2013. The Authority is providing for its share of the estimated future decommissioning costs over the remaining life of the nuclear power plant through annual charges to expense, which amounted to $7.6 million and $2.4 million in fiscal years 2015 and 2014, respectively. The decommissioning liability is included as a component of accumulated depreciation and was $250.3 million and $242.7 million at June 30, 2015 and 2014, respectively.

The Authority contributes to external trusts set up in accordance with the Arizona Nuclear Power Plant participation agreement and Nuclear Regulatory Commission requirements. As of June 30, 2015, decommissioning funds totaled approximately $171.8 million, including approximately $0.4 million of interest receivable.

Asset retirement obligation – Demolition of SJGS is projected to commence subsequent to the year 2030. Based upon the study performed by an independent engineering firm, the Authority's share of the estimated demolition costs is $47.4 million in 2008 dollars. The Authority is providing for its share of the estimated future demolition costs over the remaining life of the power plant through annual charges to expense of $1.5 million. The demolition liability is included as a component of accumulated depreciation and totaled $57.5 million and $55.9 million at June 30, 2015 and 2014, respectively.

As of June 30, 2015, the Authority has not billed participants for the cost of demolition nor has it established a demolition fund.

San Juan reclamation liability– The Authority has certain obligations relating to its ownership interests in the SJGS Unit 3, to participate in the development of plans and arrangements for the eventual reclamation of the San Juan Coal Mine after the expiration in December 2017 of the Underground Coal Sales Agreement dated August 31, 2001. The Authority is providing for its share of the estimated future reclamation costs through annual charges to expense, which initially amounted to $1.9 million at December 31, 2012. The reclamation liability is included as a component of accumulated reclamation costs and was $6.2 million at June 30, 2015.

The Authority contributes to a Reclamation Trust Fund set up in accordance with the Mine Reclamation Trust Funds Agreement among the San Juan Participants, dated June 1, 2012. As of June 30, 2015, reclamation funds totaled $2.9 million.

Note 2 – Summary of Significant Accounting Policies (continued)

Investments – Investments include United States government and governmental agency securities, guaranteed investment contracts, medium term notes, and money market accounts. These investments are reported at fair value and changes in unrealized gains and losses are recorded in the statement of revenues, expenses, and changes in net position with the exception of the guaranteed investment contracts which are recorded at amortized cost. Gains and losses realized on the sale of investments are generally determined using the specific identification method.

The Bond Indentures for the Projects and the Multiple Project Fund require the use of trust funds to account for the Authority's receipts and disbursements. Cash and investments held in these funds are restricted to specific purposes as stipulated in the Bond Indentures.

Accounts receivable – Accounts receivable consists primarily of participant receivables. As such no allowance is deemed necessary.

Prepaid and other assets – SCPPA entered into a prepaid gas contract with a supplier for a 30-year gas supply at a fixed discount and simultaneously entered into a contract with each of the project participants for the delivery of natural gas. The prepaid contracts were subsequently restructured and the term of the agreements were shortened to 27 years. SCPPA has also entered into 20-year term prepaid contracts for all of the energy generated by the Milford I Wind, Milford II Wind, and the Windy Point/Windy Flats Facilities, with corresponding power sales contracts with each project participant. (See Note 1).

Advances for capacity and energy – Advance payments to the United States Bureau of Reclamation for the uprating of the 17 generators at the Hoover Power Plant are included in advances for capacity and energy. These advances are being reduced by the principal portion of the credits on billings to the Authority for energy and capacity. The current portion of these advances is recorded under Prepaid and Other Assets in the Current Assets Section of the Combined Statements of Net Position.

Advance to IPA – Advance to IPA consists of cash transferred to IPA for reserve, contingency, and self-insurance funding and relates to the STS Project.

Unamortized premiums and discounts – Unamortized premiums and discounts are recorded as part of long-term debt and amortized over the life of the related debt issue.

Cash and cash equivalents – Cash and cash equivalents include cash and investments with original maturities of 90 days or less.

Note 2 – Summary of Significant Accounting Policies (continued)

Restricted cash and investments – Restricted cash and investments are set aside to meet externally imposed legal and contractual obligations. Restricted cash and investments are used in accordance with their requirements and include certain proceeds of the Authority's revenue bonds, as well as resources set aside for their repayment, and participant advances restricted for costs of certain capital projects.

Deferred outflow and inflow of resources – Losses on refunding related to bonds redeemed by refunding bonds are reported as deferred outflows of resources and are amortized over the shorter life of the refunding bonds, or the remaining term of bonds in accordance with GASB Statement No. 23, *Accounting and Financial Reporting for Refundings of Debt Reported by Proprietary Activities.*

In addition, the accumulated decrease in the fair value of effective hedging derivative instruments are reported as deferred outflow of resources. Under hedge accounting, the changes in the fair value of an effective hedging derivative instrument, in asset or liability positions, are reported as a deferred inflow of resources or deferred outflow of resources, respectively, on the Statements of Net Position.

See Note 10 for a description of the deferred outflows of resources and the deferred inflows of resources related to the pension.

Materials and supplies – Materials and supplies consist primarily of items for construction and maintenance of plant assets and are stated at the lower of cost or market.

Arbitrage rebate and yield restrictions – The unused proceeds from the issuance of tax-exempt debt have been invested in taxable financial instruments. The excess of earnings on investments, if any, over the amount that would have been earned if the investments had a yield equal to the bond yield or yield restricted rate, is payable to the IRS within five years of the date of the bond offering and each consecutive five years thereafter until final maturity of the related bonds.

Final maturity of the 1989 Multiple Project Bonds occurred on July 1, 2013 leaving a Surplus Amount of approximately $6.4 million and $18.4 million available to the SCPPA Mead-Phoenix and Mead-Adelanto project participants, respectively, which were received during the year ended June 30, 2014. The Surplus Amount was the result of the cumulative savings from refunding of the 1989 Multiple Project Bonds by the 1994 MA and MP Bonds. The partial refunding within five years of the original issuance triggered a recalculation of the arbitrage yield, reducing the Multiple Project Fund's rebate liability and resulted in additional savings over the remaining life of the 1989 Multiple Project Bonds. Recorded arbitrage rebate and yield restriction liabilities as of June 30, 2015, were $118,000 for Mead-Phoenix and $272,000 for Mead-Adelanto.

Note 2 – Summary of Significant Accounting Policies (continued)

Pensions – For purposes of measuring the net pension liability and deferred outflows/inflows of resources related to pensions, and pension expense, information about the fiduciary net position of SCPPA's California Public Employees' Retirement System (CalPERS), Miscellaneous plans (Plans), and additions to/deductions from the Plans' fiduciary net position have been determined on the same basis as they are reported to CalPERS. For this purpose, benefit payments (including refunds of employee contributions) are recognized when due and payable in accordance with the benefit terms. Investments are reported at fair value.

Revenues – Revenues consist of billings to participants for the sales of electric energy, natural gas, and transmission service in accordance with the participation agreements. Generally, revenues are fixed at a level to recover all operating and any debt service costs over the commercial life of the property.

In September 1998, the Palo Verde participants approved a resolution authorizing the Authority to bill the participants an additional $65 million annually through June 30, 2004 to pay for increased debt service costs as a result of a refunding completed in October 1997. In addition, the participants resolved to transfer any over billings, renewal and replacement excess funds, or surplus amounts through June 30, 2004 into the Palo Verde reserve account. On November 20, 2003, the Authority adopted a resolution to utilize the amounts on deposit in the reserve accounts to pay a portion of the operating and maintenance expenses of the Palo Verde Project starting July 1, 2004. Funds held in the reserve account as a result of this resolution totaled $14.5 million and $21.2 million as of June 30, 2015 and 2014, respectively.

Transportation costs – As a result of the sales and purchases agreements for natural gas entered into by SCPPA, the participants receive less volume than processed incurring embedded transportation costs. These costs are recorded as participants' revenue and expense to the Natural Gas Pinedale Project. At June 30, 2015 and 2014, transportation costs were approximately $179,000 and $258,000, respectively, for the Natural Gas Pinedale Project.

Non-exchange contribution – Each participant of the Magnolia Power Plant is responsible for its own share of natural gas. They may elect to bring fuel to the plant or purchase fuel from Occidental Energy Marketing, Inc. (OEMI). OEMI computes the daily imbalances of fuel volume per participant using the daily consumption data that the operating manager provides. Monthly, actual fuel burnt is reported together with the daily imbalances, participants' in kind contribution, and fuel purchases from OEMI.

Non-exchange contributions are valued at fair market value and recorded as participant revenue and fuel expense to the Magnolia Power Project. SCPPA values the participants' fuel contribution using monthly average pricing from the Project's OEMI fuel purchases. During the fiscal years ended June 30, 2015 and 2014, the participants' contribution in kind was approximately 10.3 MMBtu and 11.0 MMBtu and was valued at approximately $37.1 million and $53.7 million, respectively.

Note 2 – Summary of Significant Accounting Policies (continued)

Build America Bonds (BABs) – These are taxable municipal bonds that were created under the American Recovery and Reinvestment Act of 2009, and carry special tax credits and federal subsidies for either the bond issuer or the bondholder. BABs provide for a subsidy payment from the Department of the Treasury to be paid directly to the issuer (Direct Payment) or the bondholder (Tax Credit BABs) in an amount equal to 35% of the bond's interest. On June 9, 2010, SCPPA issued $191 million of Canyon Power 2010 Series B, Direct Payment BABs. $41.5 million of the Linden Wind 2010 Series B, Direct Payment BABs, were issued on September 28, 2010.

The budget sequestration or automatic spending cuts of the United States Government that went into effect in 2013 resulted in a 7.2% decrease of the BABs subsidies received by the Authority for the related bonds.

Note 3 – Utility Plant

At June 30, 2015, Utility Plant, net consisted of the following (amounts in thousands):

	June 30, 2015							
	GENERATION					GREEN POWER		
	Palo Verde Project	San Juan Project	Magnolia Power Project	Canyon Power Project	Apex Power Project	Hoover Uprating Project	Tieton Hydro-power	Linden Wind Energy
Utility plant								
Production	$ 723,801	$ 258,675	$ 287,009	$ 252,498	$ 289,732	$ -	$ 47,899	$ 123,082
Transmission	17,206	-	15,247	31,853	-	-	-	23,431
General	3,666	6,811	15,495	488	4,956	21	11	-
Natural gas reserves	-	-	-	-	-	-	-	-
	744,673	265,486	317,751	284,839	294,688	21	47,910	146,513
Less accumulated depreciation	758,019	204,836	109,327	36,215	15,166	21	8,158	27,857
	(13,346)	60,650	208,424	248,624	279,522	-	39,752	118,656
Construction work in progress	29,739	3,453	1,520	-	-	-	-	-
Nuclear fuel, at amortized cost	43,613	-	-	-	-	-	-	-
Net utility plant	$ 60,006	$ 64,103	$ 209,944	$ 248,624	$ 279,522	$ -	$ 39,752	$ 118,656

	TRANSMISSION			NATURAL GAS		OTHERS	
	Southern Transmission System Project	Mead-Phoenix Project	Mead-Adelanto Project	Pinedale Project	Barnett Project	SCPPA Fund	Total
Utility plant							
Production	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,982,696
Transmission	770,498	55,106	173,139	-	-	-	1,086,480
General	44,400	2,730	473	4,094	-	4,386	87,531
Natural gas reserves	-	-	-	73,191	84,416	-	157,607
	814,898	57,836	173,612	77,285	84,416	4,386	3,314,314
Less accumulated depreciation	575,885	28,004	86,871	32,643	34,158	347	1,917,507
	239,013	29,832	86,741	44,642	50,258	4,039	1,396,807
Construction work in progress	-	174	-	(17)	452	221	35,542
Nuclear fuel, at amortized cost	-	-	-	-	-	-	43,613
Net utility plant	$ 239,013	$ 30,006	$ 86,741	$ 44,625	$ 50,710	$ 4,260	$ 1,475,962

Note 3 – Utility Plant (continued)

In June, 2011, the Authority made a one-time payment to acquire an 11,500 sq. ft. building located in the city of Glendora to be used as SCPPA office facilities. The building was renovated and put into service during fiscal year 2012. Acquisition and construction costs were financed by contributions from SCPPA members. On July 18, 2013, the SCPPA Board authorized the installation of Solar Voltaic Equipment and Carports at the SCPPA Glendora Office Building. The estimated cost was financed by the SCPPA Members in accordance with their ownership interests in the SCPPA Building. (See Note 1).

At June 30, 2014 Utility Plant, net consisted of the following (amounts in thousands):

	June 30, 2014							
	GENERATION					GREEN POWER		
	Palo Verde Project	San Juan Project	Magnolia Power Project	Canyon Power Project	Apex Power Project	Hoover Uprating Project	Tieton Hydro-power	Linden Wind Energy
Utility plant								
Production	$ 713,228	$ 258,334	$ 286,103	$ 252,426	$ 288,841	$ -	$ 47,799	$ 123,082
Transmission	16,639	-	15,247	31,853	-	-	-	23,431
General	3,564	6,802	15,495	488	4,956	21	11	-
Natural gas reserves	-	-	-	-	-	-	-	-
	733,431	265,136	316,845	284,767	293,797	21	47,810	146,513
Less accumulated depreciation	730,940	193,570	98,148	26,632	3,015	21	6,686	22,043
	2,491	71,566	218,697	258,135	290,782	-	41,124	124,470
Construction work in progress	28,037	3,895	971	-	-	-	81	-
Nuclear fuel, at amortized cost	42,454	-	-	-	-	-	-	-
Net utility plant	$ 72,982	$ 75,461	$ 219,668	$ 258,135	$ 290,782	$ -	$ 41,205	$ 124,470

	TRANSMISSION			NATURAL GAS		OTHERS	
	Southern Transmission System Project	Mead-Phoenix Project	Mead-Adelanto Project	Pinedale Project	Barnett Project	SCPPA Fund	Total
Utility plant							
Production	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,969,813
Transmission	770,498	54,825	173,101	-	-	-	1,085,594
General	44,400	2,730	473	4,090	-	4,386	87,416
Natural gas reserves	-	-	-	73,126	84,117	-	157,243
	814,898	57,555	173,574	77,216	84,117	4,386	3,300,066
Less accumulated depreciation	553,131	26,477	82,348	28,538	30,242	234	1,802,025
	261,767	31,078	91,226	48,678	53,875	4,152	1,498,041
Construction work in progress	-	209	-	69	365	72	33,699
Nuclear fuel, at amortized cost	-	-	-	-	-	-	42,454
Net utility plant	$ 261,767	$ 31,287	$ 91,226	$ 48,747	$ 54,240	$ 4,224	$ 1,574,194

Note 3 – Utility Plant (continued)

A summary of changes in Utility Plant follows (amounts in thousands):

	Balance July 1, 2014	Additions	Disposals	Transfers	Balance June 30, 2015
Nondepreciable utility plant					
Land	$ 49,272	$ -	$ -	$ -	$ 49,272
Construction work in progress	33,265	16,707	-	(14,866)	35,106
Construction work in progress – gas	434	435	-	(434)	435
Nuclear fuel*	42,454	15,473	(14,313)	-	43,614
Total nondepreciable utility plant	125,425	32,615	(14,313)	(15,300)	128,427
Depreciable utility plant					
Production					
Nuclear generation (Palo Verde Project)	712,314	(566)	(1,875)	13,014	722,887
Coal-fired plant (San Juan Unit 3 Project)	260,002	-	(229)	1,475	261,248
Gas-fired plant	825,699	963	-	-	826,662
Green power	156,419	19	-	-	156,438
Transmission	1,057,199	730	(125)	363	1,058,167
General	79,083	115	(19)	14	79,193
Natural gas reserves	160,078	-	(67)	434	160,445
Total depreciable utility plant	3,250,794	1,261	(2,315)	15,300	3,265,040
Less accumulated depreciation	(1,802,025)	(117,446)	1,966	-	(1,917,505)
Total utility plant, net	$ 1,574,194	$ (83,570)	$ (14,662)	$ -	$ 1,475,962

**Nuclear fuel disposals represent amortization.*

Note 4 – Investments

The Authority's investment function operates within a legal framework established by Sections 6509.5 and 53600 et. seq. of the California Government Code, Indentures of Trust, and instruments governing financial arrangements entered into by the Authority to finance and operate Projects and the Authority's Investment Policy.

Guaranteed investment contracts (GICs) are contracts that guarantee the owner principal repayment and a specified interest rate for a predetermined period of time. GICs are typically issued by insurance companies and marketed to institutions that qualify for favorable tax status under federal laws. These types of securities provide institutions with guaranteed returns. GICs are negotiated on a case-by-case basis.

Note 4 - Investments (continued)

Based on SCPPA's Investment Policy, certain vehicles such as GICs, flexible repurchase agreements or forward debt service agreements, may be entered into only upon approval of the SCPPA Board. In addition, eligible securities and general limitations are derived from each Project's Indenture of Trust, the Government Code and SCPPA's evolving investment practices.

The operative Indentures of Trust in which securities are authorized for investment purposes relate to the Palo Verde Project Bonds, the Southern Transmission System Project Bonds, the Hoover Uprating Project Bonds, the Mead-Phoenix Project Bonds, the Mead-Adelanto Project Bonds, the San Juan Project Bonds, the Magnolia Power Project Bonds, the Pinedale Projects Bonds, the Barnett Project Bonds, Prepaid Natural Gas Project Bonds, the Canyon Power Project Bonds, the Milford Wind Phase I Project Bonds, the Milford Wind Phase II Project Bonds, the Linden Wind Project Bonds, the Tieton Project Bonds, the Windy Point/Windy Flats Bonds, and the Apex Power Project Bonds. Authorized investments for the Projects' Stabilization Fund are set forth in a resolution approved by the Board in 1996.

Eligible securities include:

- United States Treasury Securities, which are bonds or other obligations secured by the full faith and credit of the United States of America;
- Federal Agency Obligations, which have the full financial backing of the U.S. Government;
- Government Sponsored Enterprise Obligations, which are created by acts of Congress to provide liquidity for selected lending programs targeted by Congress;
- Repurchase Agreements, which are collateralized loan contracts where the seller includes a written agreement to repurchase the securities at a later date for a specified amount;
- Negotiable Certificates of Deposit, which are deposit liabilities issued by a nationally or state-chartered bank, a savings or a federal association or by a state-licensed branch of a foreign bank, which has short-term ratings of at least "A-1" by S&P and at least "P-1" by Moody's;
- Bankers' Acceptances, a short-term draft or bill of exchange guaranteed for payment at face value to the holder of the instrument on its maturity date, which has a short-term rating of at least "A-1" by S&P and at least "P-1" by Moody's;
- Commercial Paper, a short-term unsecured promissory note issued by non-financial or financial firms with a rating of at least "A-1" by S&P and at least "P-1" by Moody's;
- Medium Term Notes rated "A" or better and only those issued by corporations organized and operating within the United States, or by depository institutions licensed by the United States or any state and operating within the United States; and
- Equity-Linked Notes, which are categorized as medium-term corporate notes and are subject to the constraints set forth in the Government Code and the Authority's Investment Policy.

Note 4 – Investments (continued)

As of June 30, 2015, the Authority held the following as cash and cash equivalents and investments:

Investment Type		Carrying Value (in thousands)	Weighted Average Maturity (Years)	Percent of Portfolio
U.S. Agency Securities	$	451,743	0.80	44.6%
Guaranteed Investment Contracts		37,751	11.16	3.7%
Money Market Funds		297,825	0.08	29.4%
Commercial Paper		121,965	0.13	12.0%
Negotiable CDs		21,500	-	2.1%
Agency Discount Notes		78,925	0.19	7.8%
Bankers Acceptance		3,800	0.01	0.4%
Total	$	1,013,509	0.83	100.0%

The "weighted average maturity in years" calculation assumes that all investments are held until maturity.

Note 4 – Investments (continued)

Investments at June 30, 2015 are as follows (amounts in thousands):

	GENERATION					GREEN POWER						TRANSMISSION		
	Palo Verde Project	San Juan Project	Magnolia Power Project	Canyon Power Project	Apex Power Project	Hoover Uprating Project	Tieton Hydro-power	Milford I Wind	Milford II Wind	Windy Point Project	Linden Wind Energy	Southern Transmission System Project	Mead-Phoenix Project	Mead-Adelanto Project
U.S. Agencies	$ 177,426	$ 7,422	$ 39,719	$ 19,519	$ 13,487	$ 1,697	$ 4,956	$ 26,769	$ 6,072	$ 13,296	$ 3,804	$ 9,615	$ -	$ -
Agency Discount Notes	20,738	6,097	10,499	-	10,000	-	-	2,000	-	2,000	-	5,000	-	-
Negotiable CDs	-	-	1,700	-	-	-	-	1,600	2,400	5,700	-	4,000	1,300	3,300
Commercial Paper	5,000	-	6,994	3,199	24,494	1,999	-	-	-	5,000	-	22,500	2,900	12,397
GICs	14,513	-	3,863	-	-	-	-	-	-	-	-	7,789	-	-
Bankers Acceptance	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Money Market Funds	29,069	19,444	26,839	11,949	24,107	881	3,133	12,199	9,202	23,505	8,211	45,449	3,377	12,860
Total	$ 246,746	$ 32,963	$ 89,614	$ 34,667	$ 72,088	$ 4,577	$ 8,089	$ 42,568	$ 17,674	$ 49,501	$ 12,015	$ 94,353	$ 7,577	$ 28,557
Restricted investments	$ 189,229	$ 11,975	$ 52,576	$ 22,718	$ 37,981	$ 3,136	$ 4,956	$ 26,267	$ 3,249	$ 21,293	$ 2,303	$ 48,904	$ 2,900	$ 14,397
Unrestricted investments	23,742	-	-	-	-	560	-	2,502	2,823	3,003	1,501	-	-	-
Cash and cash equivalents	33,775	20,988	37,038	11,949	34,107	881	3,133	13,799	11,602	25,205	8,211	45,449	4,677	14,160
Total	$ 246,746	$ 32,963	$ 89,614	$ 34,667	$ 72,088	$ 4,577	$ 8,089	$ 42,568	$ 17,674	$ 49,501	$ 12,015	$ 94,353	$ 7,577	$ 28,557

	POWER PURCHASE AGREEMENTS							NATURAL GAS			MISCELLANEOUS			
	Ormat Geo-thermal Project	MWD Small Hydro	Pebble Springs	Ameresco Chiquita Landfill Gas	Campbell Wild Rose Geothermal	Copper Mountain Solar 3	Columia Solar 2	Pinedale Project	Barnett Project	Prepaid Natural Gas	Project Development Fund	Projects' Stabilization Fund	SCPPA Fund	Total
U.S. Agencies	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 21,689	$ -	$ -	$ 106,272	$ -	$ 451,743
Agency Discount Notes	-	-	1,000	-	-	-	-	1,000	-	-	-	20,591	-	78,925
Negotiable CDs	-	-	-	-	-	-	-	-	1,500	-	-	-	-	21,500
Commercial Paper	-	-	-	-	-	9,994	-	-	7,998			19,490	-	121,965
GICs	-	-	-	-	-	-	-	-	-	11,586	-	-	-	37,751
Bankers Acceptance	-	-	-	-	-	3,800	-	-	-	-	-	-	-	3,800
Money Market Funds	1,817	1,339	2,761	1,418	3,369	13,182	1,885	8,303	12,381	4,476	6,485	10,019	165	297,825
Total	$ 1,817	$ 1,339	$ 3,761	$ 1,418	$ 3,369	$ 26,976	$ 1,885	$ 9,303	$ 43,568	$ 16,062	$ 6,485	$ 156,372	$ 165	$ 1,013,509
Restricted investments	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 31,187	$ 11,586	$ -	$ 146,353	$ -	$ 631,010
Unrestricted investments	-	-	1,000	-	-	9,994	-	-	-	-	-	-	-	45,125
Cash and cash equivalents	1,817	1,339	2,761	1,418	3,369	16,982	1,885	9,303	12,381	4,476	6,485	10,019	165	337,374
Total	$ 1,817	$ 1,339	$ 3,761	$ 1,418	$ 3,369	$ 26,976	$ 1,885	$ 9,303	$ 43,568	$ 16,062	$ 6,485	$ 156,372	$ 165	$ 1,013,509

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
NOTES TO COMBINED FINANCIAL STATEMENTS

Note 4 – Investments (continued)

Investments at June 30, 2014 are as follows (amounts in thousands):

	GENERATION					GREEN POWER						TRANSMISSION		
	Palo Verde Project	San Juan Project	Magnolia Power Project	Canyon Power Project	Apex Power Project	Hoover Uprating Project	Tieton Hydro-power	Milford I Wind	Milford II Wind	Windy Point Project	Linden Wind Energy	Southern Transmission System Project	Mead-Phoenix Project	Mead-Adelanto Project
U.S. Agencies	$ 190,588	$ 7,902	$ 43,995	$ 19,297	$ 5,477	$ 2,242	$ 5,383	$ 24,019	$ 3,273	$ 10,312	$ 2,274	$ 9,509	$ -	$ -
Agency Discount Notes	9,000	-	7,700	2,000	-	1,300	-	2,600	-	2,500	1,100	8,100	-	-
Negotiable CDs	-	4,500	7,900	-	-	-	-	-	-	-	-	13,000	1,800	3,100
Commercial Paper	2,900	3,498	-	2,000	18,000	-	-	4,600	3,700	10,000	1,300	27,694	500	14,800
GICs	21,248	7,798	3,863	-	-	-	-	-	-	-	-	7,789	-	-
Money Market Funds	18,189	19,843	25,845	9,273	33,736	968	2,808	15,198	11,304	24,882	7,306	32,731	4,422	10,408
Total	$ 241,925	$ 43,541	$ 89,303	$ 32,570	$ 57,213	$ 4,510	$ 8,191	$ 46,417	$ 18,277	$ 47,694	$ 11,980	$ 98,823	$ 6,722	$ 28,308
Restricted investments	$ 194,156	$ 21,213	$ 55,558	$ 23,297	$ 23,477	$ 2,982	$ 5,383	$ 31,219	$ 6,973	$ 22,812	$ 4,674	$ 66,092	$ 2,300	$ 17,900
Unrestricted investments	30,477	-	-	-	-	560	-	-	-	-	-	-	-	-
Cash and cash equivalents	17,292	22,328	33,745	9,273	33,736	968	2,808	15,198	11,304	24,882	7,306	32,731	4,422	10,408
Total	$ 241,925	$ 43,541	$ 89,303	$ 32,570	$ 57,213	$ 4,510	$ 8,191	$ 46,417	$ 18,277	$ 47,694	$ 11,980	$ 98,823	$ 6,722	$ 28,308

	POWER PURCHASE AGREEMENTS						NATURAL GAS			MISCELLANEOUS			
	Ormat Geo-thermal Project	MWD Small Hydro	Pebble Springs	Ameresco Chiquita Landfill Gas	Campbell Wild Rose Geothermal	Copper Mountain Solar 3	Pinedale Project	Barnett Project	Prepaid Natural Gas	Project Development Fund	Projects' Stabilization Fund	SCPPA Fund	Total
U.S. Agencies	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 21,550	$ -	$ -	$ 106,267	$ -	$ 452,088
Agency Discount Notes	-	-	1,000	-	-	-	-	-	-	-	7,000	-	42,300
Negotiable CDs	-	-	-	-	-	-	-	1,400	-	-	11,500	-	43,200
Commercial Paper	-	-	-	-	-	-	-	5,000	-	-	6,200	-	100,192
GICs	-	-	-	-	-	-	-	-	11,579	-	-	-	52,277
Money Market Funds	2,819	1,221	3,123	2,041	67	1,615	19,290	16,109	6,862	65	20,826	314	291,265
Total	$ 2,819	$ 1,221	$ 4,123	$ 2,041	$ 67	$ 1,615	$ 19,290	$ 44,059	$ 18,441	$ 65	$ 151,793	$ 314	$ 981,322
Restricted investments	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 27,950	$ 11,579	$ -	$ 130,967	$ -	$ 648,532
Unrestricted investments	-	-	-	-	-	-	-	-	-	-	-	-	31,037
Cash and cash equivalents	2,819	1,221	4,123	2,041	67	1,615	19,290	16,109	6,862	65	20,826	314	301,753
Total	$ 2,819	$ 1,221	$ 4,123	$ 2,041	$ 67	$ 1,615	$ 19,290	$ 44,059	$ 18,441	$ 65	$ 151,793	$ 314	$ 981,322

Note 4 – Investments (continued)

Interest rate risk – The Authority's investment policy limits the maturity of its investments to a maximum of five years for investments in the United States Treasury, Federal Agency, and Government Sponsored Enterprise securities, excluding: investments held in Project Debt Service Reserve; long-term commitments or agreements approved by the Authority's Board; five years for medium term corporate notes; 270 days for commercial paper; 180 days for bankers' acceptances; and one year for negotiable certificates of deposits.

Credit risk – Under its investment policy and the State of California Government Code, the Authority is subject to the prudent investor standard of care in managing all aspects of its portfolios. As an investment standard, each investment shall be made with "judgment and care under circumstances then prevailing, which a person of prudence, discretion and intelligence would exercise in the management of his/her affairs, not in regard for speculation, but in regard to the permanent disposition of funds, considering the probable income as well as the probable safety of the capital to be invested." The Authority's investment policy does not preclude active management of the portfolio to address market opportunities. All transactions shall be undertaken in the best interest of the Authority and its participants.

The Authority's investment policy specifies that all project funds may be invested in shares of beneficial interest for temporary periods, pending disbursement or reinvestment as allowed under the state of California Government Code (Code). The Code requires that the fund must have either 1) attained the highest ranking or highest letter and numerical rating provided by not less than two nationally recognized statistical rating organizations (NRSRO) or 2) retained an investment advisor registered or exempt from registration with the Securities and Exchange Commission with not less than five years' experience managing money market mutual funds with assets under management in excess of $500 million. As of June 30, 2015, money market funds in the portfolios with Bank of New York Mellon have attained the following ratings: AAAm by Standard and Poor's, and AAA-mf by Moody's Investors Service; while bank deposits in the portfolios with US Bank have attained ratings of A-1+ by Standard and Poor's, P-1 by Moody's Investors Service, and F1+ by Fitch Ratings.

The U.S. government agency securities in the portfolio consist of securities issued by government-sponsored enterprises, which are not explicitly guaranteed by the U.S. government. As of June 30, 2015 and 2014, the U.S. government agency securities in the portfolio carried the highest possible credit ratings by the NRSRO that rated them.

The Guaranteed Investment Contracts in the portfolio with American International Group (AIG) consist of securities issued by corporations and carry a rating of A- by Standard and Poor's, Baa1 by Moody's Investors Service and BBB+ by Fitch Rating.

Note 4 – Investments (continued)

The Investment Agreement Contract with American General Life consists of securities issued by corporations and carries a rating of A+ by Standard and Poor's, A2 by Moody's and A+ by Fitch Ratings.

The Investment Agreement Contract in the portfolio with Assured Guaranty (formerly Financial Security Assurance) consists of securities issued by corporations and carries a rating of AA by Standard and Poor's, and A3 by Moody's Investors Service.

Concentration of credit risk – The Authority's investment policy specifies a 50% to 100% limitation on the amount that can be invested in U.S. government agency securities, except in certain issues of other Authority projects, such as the Mead-Adelanto and Mead-Phoenix projects.

Of the Authority's total investments as of June 30, 2015, $180 million (18%) was invested in securities issued by the Federal Home Loan Bank; $44 million (4%) was invested with Farm Credit Bank; $212 million (21%) was invested in securities issued by the Federal National Mortgage Association; $94 million (9%) was invested with Federal Home Loan Mortgage; $22 million (2%) was invested in Certificates of Deposit; $122 million (12%) was invested in Commercial Paper; and $15 million (1%) was invested in GICs with Assured Guaranty.

Of the Authority's total investments as of June 30, 2014, $129 million (13%) was invested in securities issued by the Federal Home Loan Bank; $235 million (24%) was invested in securities issued by the Federal National Mortgage Association; $58 million (6%) was invested with Federal Home Loan Mortgage; $100 million (10%) was invested in Commercial Paper; and $21 million (2%) was invested in GICs with Assured Guaranty.

Note 5 – Derivative Instruments

Objective of the swaps – SCPPA uses derivative instruments to hedge its exposure to changing interest rates through the use of interest rate swaps and also to manage its exposure to fluctuating natural gas prices through the use of natural gas hedge contracts. An interest rate swap is the exchange of payments between SCPPA and a counterparty in order to potentially obtain a lower cost of funding than traditional fixed rate bonds, or to hedge interest rate exposure on SCPPA's assets or liabilities. The Authority has entered into separate pay-fixed, receive-variable interest rate swaps and four basis swaps to produce savings or to result in lower costs over the life of each transaction than what the Authority would have paid using fixed-rate debt. While these instruments carry additional risks, SCPPA's swap policy and favorable negotiations have helped to reduce such risks.

Note 5 – Derivative Instruments (continued)

The Authority has adopted Statement No. 53 of the GASB, *Accounting and Financial Reporting for Derivative Instruments (GASB 53)*. This Statement addresses the recognition, measurement, and disclosure of information regarding derivative instruments. In accordance with GASB 53, SCPPA recognizes the changes in fair values of effective hedging derivative instruments as either deferred inflows or outflows of resources on the Authority's Statements of Net Position and includes changes in the fair value of an ineffective derivative instrument in earnings.

For fiscal year ended June 30, 2014, the balance for the swaps deemed to qualify for effective hedge accounting under GASB 53 was a net liability and corresponding deferred outflows of resources of $15.4 million. During fiscal year ended June 30, 2015, the liability increased by $7.7 million for an ending liability balance of $23.1 million. For the swaps that were deemed ineffective derivative instruments under GASB 53, the changes were reported in the statement of operations. The net liability balance for fiscal year ended June 30, 2014 for the ineffective derivative instruments was $39.8 million, but during fiscal year ended June 30, 2015, the liability decreased by $28.4 million for an ending liability balance of $11.4 million.

Terms, fair values, and credit risk – The terms, including the fair values and credit ratings of the counterparties under the outstanding swaps as of June 30, 2015, are included in the table below. In most cases, and with the exclusion of basis swaps, the notional amount of any swap matches the principal amount of the associated debt. Except as discussed under the rollover risk, and when associated with basis swaps, the Authority's swap agreements contain scheduled reductions to outstanding notional amounts that are expected to approximately follow scheduled or anticipated reductions in the associated "bonds payable" category.

	Notional Amount (in thousands)	Effective Date	Fixed Rate Paid	Variable Rate Received	Fair Values (in thousands)	Swap Termination Date	Counterparty Credit Rating*
MAG 2010-1 Swap (Barclays)	$ 100,000	5/11/2010	SIFMA	80.4% of 3-month LIBOR	$ (198)	7/1/2036	A-/A2/A
MAG 2010-2 Swap (RBC)	100,000	5/12/2010	SIFMA	81% of 3-month LIBOR	24	7/1/2036	AA-/Aa3/AA
MAG 2009-1 Swap (BNYMellon)	110,020	5/1/2012	3.125%	SIFMA	(13,248)	7/1/2036	AA-/Aa2/AA
MAG 2009-2 Swap (JPMorgan)	109,905	8/21/2012	3.139%	SIFMA	(13,529)	7/1/2036	A+/Aa3/AA-
MA 2007 Swap	100,000	6/1/2018	1-month LIBOR	100% of 10-yr LIBOR CMS rate less .414%	2,229	9/15/2030	A+/Aa3/AA-
PNG 2007 Swap	36,000	5/1/2009	5.0475%	67% of 3-Month LIBOR plus 1.47%	(9,882)	11/1/2035	A-/A3/A

* S&P/Moody's/Fitch ratings

Note 5 – Derivative Instruments (continued)

- **MAG 2010-1 Swap** – In May 2010, SCPPA executed $100 million Securities Industry and Financial Markets Association Swap Index (SIFMA)/LIBOR floating-to-floating basis swap related to Magnolia Power Project A Refunding Bonds 2009-1. SCPPA pays the 6-month average of the weekly reset SIFMA Municipal Swap Index semi-annually on an Actual/Actual basis in exchange for receiving 80.4% of average 3-Month LIBOR, reset quarterly and paid semi-annually on an Actual/360 day basis. The swap expires on July 1, 2036.

- **MAG 2010-2 Swap** – In May 2010, SCPPA executed $100 million SIFMA/LIBOR floating-to-floating basis swap related to Magnolia Power Project A Refunding Bonds 2009-2. SCPPA pays the 6-month average of the weekly reset SIFMA Municipal Swap Index semi-annually on an Actual/Actual basis in exchange for receiving 81.0% of average 3-Month LIBOR, reset quarterly and paid semi-annually on an Actual/360 day basis. The swap expires on July 1, 2036.

- **MAG 2009-1 Swap (restated/novated)** – This swap transaction amends the MAG 2007-1 Swap, which had an original trade date of April 30, 2007. The transaction was amended and restated as of April 21, 2009. The Authority pays its counterparty a fixed rate of 3.125% in exchange for receiving 100% of the SIFMA on a notional amount of $110.0 million. In order to provide more favorable terms to the participants, SCPPA made a payment of $15.7 million to the counterparty which has been deferred and is being amortized as an interest yield adjustment over the life of the swap. The amendment allowed the parties to re-coupon the swaps, change the collateral posting requirements, and to move to uninsured swaps. In May 2012, the swap was novated to a new counterparty and the swap documents were amended to raise the collateral threshold.

- **MAG 2009-2 Swap (amended/restated)** – This swap transaction amends the MAG 2007-1 Swap. The original transaction was novated from Bear Stearns to JP Morgan on November 6, 2008 and was amended and restated on April 21, 2009. The Authority pays its counterparty a fixed rate of 3.139% in exchange for receiving 100% of the SIFMA Index on a notional amount of $109.9 million. In order to provide more favorable terms to the participants, SCPPA made a payment of $15.7 million to the counterparty which has been deferred and is being amortized as an interest yield adjustment over the life of the swap. The amendment allowed the parties to re-coupon the swaps, change the collateral posting requirements, and to move to uninsured swaps. In August 2012, the swap documents were amended to raise the collateral threshold.

Note 5 – Derivative Instruments (continued)

- **STS Swaption/Swap (terminated)** – In March 2015, the STS 2000 Series A Bonds were refunded and the STS 2000 Swap/Swaption was terminated.

- **MA 2007 Swap (amended)** – In January 2007, the Authority entered into a Constant Maturity Swap (CMS) in connection with its outstanding Mead-Adelanto Project bonds. The transaction consisted of a $100 million basis swap and does not relate to any single series of the Mead-Adelanto bonds. The amended swap terms became effective on February 1, 2008 and the Authority pays the swap counterparty 100% of the one month LIBOR in exchange for receiving 100% of the 10-year LIBOR minus 41.4 basis points. The swap expires on September 15, 2030. On November 5, 2008 the MA 2007 Swap was novated from Bear Stearns to JP Morgan. In addition, the swap was suspended until November 1, 2011. As part of the novation, the credit terms of the existing swap agreements were maintained and SCPPA received $4.1 million from JP Morgan as compensation for the suspension of the cash flows of the MA 2007 CMS. The $4.1 million was deferred to be amortized over the suspension term.

  In June 2010, the MA 2007 CMS Agreement was amended to extend the suspension period from November 1, 2011 to June 1, 2018. SCPPA received $5 million as compensation for the suspension of the cash flows of the swap, which was deferred and is being amortized over the suspension term. The credit terms of the existing swap agreements remains unchanged.

- **MA 2004 Swap (terminated)** – In September 2012, the Mead-Adelanto 2008 Series A and B Bonds were refunded and the MA 2004 Amended Swap terminated. In connection with the issuance of the 2004 Mead-Adelanto Revenue Bonds Series A auction-rate security in May 2004, the Authority entered into an interest rate swap on March 3, 2004. The floating-to-fixed rate swap created synthetic fixed-rate debt for the Authority. The Authority received approximately $5.9 million in an upfront payment in connection with the execution of the swap, which has been deferred and amortized as an interest yield adjustment over the life of the swap. The MP 2004 bonds were refunded on October 2, 2008 and the related interest rate swap transferred to the MA 2008 Refunding Bonds.

- **PNG 2007 Swap** – In October 2007, SCPPA entered into an interest rate swap agreement in connection with the issuance of the Prepaid Natural Gas Project No. 1 Series 2007B Bonds. The swap hedges the interest-rate risk on the LIBOR Floating-rate bonds, where SCPPA pays a fixed rate of 5.0475% in exchange for receiving 67% of three-month LIBOR plus 1.47%. The floating index on the swap exactly matches the coupon on the Bonds and therefore provides a hedge with no tax or basis risk. The swap expires on November 1, 2035.

Note 5 – Derivative Instruments (continued)

- **PNG 2007 Commodity Swap** – At the same time, SCPPA also entered into five commodity price swap agreements, on behalf of each of the Prepaid Natural Gas Project No. 1 Participants, in order to hedge against reductions to its gas sale revenues resulting from changes in monthly market index prices. SCPPA pays a floating natural gas price over a 30-year period and receives specified fixed natural gas prices at an agreed pricing point as determined in the Prepaid Natural Gas No. 1 Agreements. The swaps became effective on July 1, 2008 and will all expire on September 30, 2035.

Fair value – Fair values take into consideration the prevailing interest rate environment, the specific terms and conditions of a given transaction, and any upfront payments that were received. All fair values were estimated using the zero-coupon discounting method. This method calculates the future payments required by the swap, assuming that the current forward rates implied by the yield curve are the market's best estimate of future spot interest rates. These payments are then discounted using the spot rates implied by the current yield curve for a hypothetical zero-coupon rate bond due on the date of each future net settlement on the swaps. While some of SCPPA's current mark to market values are negative, this valuation would be realized only if the swaps were terminated at the valuation date, and only SCPPA retains the right to optionally terminate most of the transactions.

Interest-rate risk – Interest rate risk is the risk that changes in interest rates will adversely affect the fair values of SCPPA's financial instruments or cash flows. SCPPA is exposed to interest-rate risk on its pay-fixed, receive variable interest rate swaps. As the LIBOR or the Securities Industry and Financial Markets Association (SIFMA) swap index decreases, SCPPA's net payment on swaps increases. In addition, SCPPA is exposed to interest rate risk if the counterparty to the swap defaults or if the swap is terminated.

Market access risk – Market access risk is the risk that SCPPA will not be able to enter credit markets or that credit will become more costly. SCPPA's financial rating is tied to the credit strength of the major participants of the specific project for which each financial instrument is issued. SCPPA is also exposed to market access risks caused by disruptions in the municipal bond market.

Credit risk – As of June 30, 2015, the net fair values of the Authority's applicable swaps for which payments were made were negative for each counterparty except for the MA 2007 and MAG 2009-2 swaps. However, should interest rates change and the fair values of the swaps become positive, the Authority may be exposed to credit risk in the amount of the derivatives' fair value.

The swap agreements contain varying collateral agreements with the counterparties. The swaps require full collateralization of the fair value of the swap should the counterparty's (or if applicable, the guarantors of the counterparty's) credit rating fall below AA- as issued by Standard & Poor's or Aa3 as issued by Moody's Investors Service for the MA 2007 Swaps; A/A2 for the PNG 2007 Commodity Swap; and A-/A3 for the MAG 2010-1, MAG 2010-2, MAG 2009-1, and MAG 2009-2. Collateral on all swaps is to be in the form of U.S. government securities held by a third-party custodian.

Note 5 - Derivative Instruments (continued)

The swap agreements provide that when the Authority has more than one derivative transaction with a given counterparty involving the same Authority project (and having the same swap/bond insurer), should one party become insolvent or otherwise default on its obligations, close-out netting provisions permit the non-defaulting party to accelerate and terminate all such related transactions and net the transactions' fair values so that a single sum will be owed by, or owed to, the non-defaulting party.

Basis risk - Basis risk is the risk that the interest rate paid by the Authority on underlying variable rate bonds to bondholders exceeds the variable swap rate received from the counterparty, and the risk that both legs of a basis swap are not exactly equal. With the exception of the PNG 2007 Swap, the Authority bears basis risk on each of its swaps. The PNG 2007 Swap is perfectly hedged since the counterparty pays the Authority its actual variable bond rate on the related bonds. All the other swaps have a basis risk since under each of those swaps the Authority received a percentage of LIBOR or a percentage of, or spread to, SIFMA to offset the actual variable bond rate or variable swap rate the Authority pays on any related bonds or on any basis swap. The Authority is exposed to basis risk should the floating rate that it receives on a swap be less than the actual variable rate the Authority pays on any related bonds; or in the case of the floating-to-floating fixed-spread basis swap, less than the variable rate paid to the swap counterparty.

Depending on the magnitude and duration of any basis risk shortfall, the expected cost savings from a swap may not be fully realized.

The following is a summary of interest rates paid to and received from the counterparties as of June 30, 2015:

	MAG 2009-1 Swap	MAG 2009-2 Swap	MAG 2010-1 Swap	MAG 2010-2 Swap	PNG 2007 Swap
Payments to counterparty	3.125%	3.139%	0.075%	0.075%	5.048%
Less, variable payments from counterparty	0.075%	0.075%	0.220%	0.222%	1.656%
Net interest-rate swap payments	3.050%	3.064%	-0.145%	-0.147%	3.392%
Add, variable-rate bond coupon payments	0.050%	0.060%	N/A	N/A	1.656%
Synthetic interest rate on bonds	3.100%	3.124%	-0.145%	-0.147%	5.048%

Termination risk - The Authority or the counterparty may terminate any of the swaps if the other party fails to perform under the terms of the contract. In addition, the Swap/Swaption provides the counterparty with an option to cancel the swap agreement if the consecutive 180-day averaged rate of the SIFMA index exceeds 7.0%. If any of the swaps were terminated, any associated variable rate bonds would no longer be hedged to a fixed rate. If at the time of termination the swap has a negative fair value, the Authority would be liable to the counterparty for a payment equal to the swap's fair value.

Note 5 – Derivative Instruments (continued)

Rollover risk – Rollover risk is the risk that the swap contract is not co-terminus with the related bonds. The Authority is exposed to rollover risk on the STS Swap/Swaption because the counterparty has the option to terminate the agreement prior to the maturity of the associated debt. In the event that this swap terminates, the Authority would be exposed to variable interest rates on the underlying bonds.

Swap payments and associated debt – Using rates as of June 30, 2015, debt service requirements of the Authority's outstanding variable rate debt and net swap payments are as follows. As rates vary, variable rate bond interest payments and net swap payments will vary.

	(amounts in thousands)			
	Variable-Rate Bonds		Interest-Rate	
Fiscal Year Ending June 30,	Principal	Interest	Swaps, Net	Total
2016	$ 725	$ 138	$ 7,456	$ 7,594
2017	750	137	7,434	7,571
2018	785	137	7,410	7,547
2019	815	136	7,385	7,521
2020	850	136	7,359	7,495
2021–2025	25,175	656	35,437	36,093
2026–2030	164,495	509	27,556	28,065
2031–2035	146,790	609	17,622	18,231
2036–2040	149,890	35	1,962	1,997
	$ 490,275	$ 2,493	$ 119,621	$ 122,114

Note 5 - Derivative Instruments (continued)

The following table shows the changes in fair value of derivative instruments (amounts in thousands):

Description	June 30, 2014	Change in Fair Value	June 30, 2015
Assets			
Mead Adelanto – Derivative instruments	$ 752	$ 1,477	$ 2,229
	$ 752	$ 1,477	$ 2,229
Deferred outflows of resources			
Magnolia – Deferred outflows	$ 6,856	$ 6,416	$ 13,272
Prepaid Natural Gas – Deferred outflows	8,537	1,345	9,882
	$ 15,393	$ 7,761	$ 23,154
Liabilities			
Magnolia – Derivative instruments	$ 19,419	$ 7,556	$ 26,975
STS – Derivative instruments	28,028	(28,028)	-
Prepaid Natural Gas – Derivative instruments	8,537	1,345	9,882
	$ 55,984	$ (19,127)	$ 36,857

Note 6 – Long-Term Debt

Long-term debt outstanding at June 30, 2015 consisted of "new money" bonds, refunding bonds, and subordinate refunding bonds due in varying annual amounts through July 1, 2042. The new money bonds were issued to finance the purchase and construction or acquisition of the Authority's interest in each of the Projects. The refunding and subordinate refunding bonds were issued to refund specified new money bonds.

In accordance with the bond indentures, the new money bonds and refunding bonds are special, limited obligations of the Authority. With the exception of the Magnolia Power Project B, Lease Revenue Bonds (City of Cerritos, California) 2003-1 (Project B Bonds), the bonds issued by each project are payable solely from and secured solely by interests in that project as follows:

- Proceeds from the sale of bonds;
- All revenues, incomes, rents, and receipts attributable to that project and interest earned on securities held under the bond indenture or indentures; and
- All funds established by the indenture or indentures.

Note 6 – Long-Term Debt (continued)

The Authority has agreed to certain covenants with respect to bonded indebtedness, including the requirement to enforce the natural gas, power, and transmission sales agreements with the participants. At the option of the Authority, all outstanding new money bonds and refunding bonds are subject to redemption prior to maturity, except for the 2006-1 Magnolia Revenue Bonds; the 2013 Series A and B Subordinate Refunding Bonds, the 2012 Series A Subordinate Refunding Bonds, the 2011 Series A Subordinate Refunding Bonds, and portions of the 1988A Refunding Bonds, the 1992, the 2008A, and the 2009A Subordinate Refunding Bonds issued for the Southern Transmission System; the 2012 Series A Mead-Phoenix and Mead-Adelanto Bonds; the 2007 Series A and B Prepaid Natural Gas Project No. 1 Bonds; portions of the 2010 Series A and B Canyon Power Revenue Bonds; portions of the 2010-1 Milford I Wind Revenue Bonds; portions of the 2010 Series A Linden Wind Revenue Bonds; and portions of the 2010-1 Windy Point/Windy Flats Revenue Bonds.

Variable rate debt includes debt with rates based on daily, weekly, and long-term rates as determined by a Remarketing Agent.

Note 6 – Long-Term Debt (continued)

A summary of changes in long-term debt follows (amounts in thousands):

	GENERATION						GREEN POWER				
	Palo Verde Project	San Juan Project	Magnolia Power Project	Canyon Power Project	Apex Power Project	Hoover Uprating Project	Tieton Hydro-power	Milford I Wind	Milford II Wind	Windy Point Project	Linden Wind Energy
Total long-term debt at June 30, 2014	$ 36,130	$ 60,161	$ 331,564	$ 309,045	$ 333,684	$ 6,127	$ 50,836	$ 214,773	$ 157,200	$ 488,305	$ 132,382
Total debt due within one year at June 30, 2014	11,330	13,200	10,565	-	-	1,835	815	8,450	5,270	18,535	3,530
Total debt at June 30, 2014	47,460	73,361	342,129	309,045	333,684	7,962	51,651	223,223	162,470	506,840	135,912
Principal payments	(11,330)	-	(10,565)			(1,835)	(815)	(8,450)	(5,270)	(18,535)	(3,530)
Revenue bonds issued	-	-	-	-		-	-	-	-	-	-
Bonds refunded/defeased	-	(71,880)	-	-	-	-	-	-	-	-	-
Refunding bonds issued	-	42,935	-	-	-	-	-	-	-	-	-
Change in unamortized premiums & discounts	-	(1,481)	(1,156)	(1,058)	(747)	(16)	(65)	(1,249)	(2,060)	(5,801)	(959)
Total debt at June 30, 2015	36,130	42,935	330,408	307,987	332,937	6,111	50,771	213,524	155,140	482,504	131,423
Total debt due within one year at June 30, 2015	(11,690)	(21,590)	(10,985)	-	(9,335)	(1,930)	(840)	(8,820)	(5,530)	(19,390)	(3,670)
Total long-term debt at June 30, 2015	$ 24,440	$ 21,345	$ 319,423	$ 307,987	$ 323,602	$ 4,181	$ 49,931	$ 204,704	$ 149,610	$ 463,114	$ 127,753

	TRANSMISSION			NATURAL GAS			
	Southern Transmission System Project	Mead-Phoenix Project	Mead-Adelanto Project	Pinedale Project	Barnett Project	Prepaid Natural Gas	Total
Total long-term debt at June 30, 2014	$ 681,723	$ 35,928	$ 120,185	$ 24,763	$ 58,162	$ 312,724	$ 3,353,692
Total debt due within one year at June 30, 2014	50,885	5,215	17,385	2,219	5,211	3,875	158,320
Total debt at June 30, 2014	732,608	41,143	137,570	26,982	63,373	316,599	3,512,012
Principal payments	(50,885)	(5,215)	(17,385)	(2,219)	(5,211)	(3,875)	(145,120)
Revenue bonds issued	-	-	-	-	-	-	-
Bonds refunded/defeased	(227,005)	-	-	-	-	-	(298,885)
Refunding bonds issued	230,100	-	-	-	-	-	273,035
Change in unamortized premiums & discounts	35,921	(718)	(2,925)	-	-	(262)	17,424
Total debt at June 30, 2015	720,739	35,210	117,260	24,763	58,162	312,462	3,358,466
Total debt due within one year at June 30, 2015	(53,085)	(5,480)	(17,690)	(2,274)	(5,326)	(4,075)	(181,710)
Total long-term debt at June 30, 2015	$ 667,654	$ 29,730	$ 99,570	$ 22,489	$ 52,836	$ 308,387	$ 3,176,756

Note 6 - Long-Term Debt (continued)

Palo Verde Project - Debt consists of subordinate refunding series bonds with variable interest rates and final maturities during 2018.

San Juan Project - Debt consists of refunding series bonds with fixed interest rates of 0.79% and final maturities during 2017.

San Juan Power Project Refunding Bonds - On December 19, 2014, SCPPA issued $42,935,000 of San Juan Unit 3 Power Project 2014 Series A Refunding Bonds. These fixed rate bonds were issued for the purpose of refunding the outstanding 2005 Refunding Series A bonds and to pay costs of issuance related to the 2014 bonds. The transaction generated 7% or over $4.96 million in net present value savings. The transaction resulted in a net loss for accounting purposes of approximately $111,000.

Magnolia Power Project - Debt consists of revenue and refunding series bonds with variable and fixed interest rates between 3.00% and 5.00% with final maturities occurring in 2036.

Of the outstanding Magnolia Power Project Revenue Bonds, $124 million of "Project B Bonds" are secured by lease rental payments to be made by the City of Cerritos (the City) in connection with the lease of certain facilities and premises owned by the City to the Authority and the leaseback of such facilities and premises to the City. The Base Rental Payments will be equal to the principal and interest on the Project B Bonds. In accordance with the Assignment Agreement between the Authority and the Trustee, the Authority will assign certain of its rights under the lease, including its right to receive the Base Rental Payments, to the Trustee for the benefit of the owners of the Project B Bonds.

The City has covenanted to budget and appropriate sufficient funds to make all payments required to be made under the lease. The lease has a term of 55 years.

Canyon Power Project - As of June 30, 2015, debt consists of revenue bonds with fixed interest rates ranging from 4.00% to 5.94% and final maturity occurring in 2040.

On June 9, 2010 the 2010 Series B Bonds were issued as Build America Bonds that are "qualified bonds" under the provisions of the American Recovery and Reinvestment Act of 2009. The interest on these bonds will not be excluded from gross income for federal income tax purposes, but will be exempt from the State of California personal income taxes. As such, the Authority may receive a cash subsidy from the United States Treasury up to 35% of the interest payable on the 2010 Series B Bonds which is applied to offset the interest costs of the 2010 Series B Bonds.

Apex Power Project - Debt consists of revenue bonds with fixed interest rates between 0.446% and 5.00% and final maturity occurring in 2038.

Note 6 – Long-Term Debt (continued)

Apex Power Project Revenue Bonds – On March 26, 2014, SCPPA issued $151,880,000 2014 Series A (Tax-Exempt) and $166,980,000 2014 Series B (Taxable) Apex Power Project Revenue Bonds, together the "2014 Bonds". These fixed rate bonds were issued to provide funds to pay the acquisition costs of the Apex Power Project; to pay the costs of certain replacement parts for and capital improvements to the Project; to fund a debt service reserve account; and to pay the costs of issuance relating to the 2014 Bonds.

Hoover Uprating Project – Debt consists of refunding series bonds with fixed interest rates of 5.25% and a final maturity occurring in 2017.

Tieton Hydropower Project – As of June 30, 2015, debt consists of revenue bonds with fixed interest rates between 3.686% and 5.798% and a final maturity occurring in 2040.

Milford I Wind Project – As of June 30, 2015, debt consists of revenue bonds with fixed interest rates ranging from 3.00% to 5.00% and final maturity occurring in 2030.

Milford II Wind Project – As of June 30, 2015, debt consists of revenue bonds with fixed interest rates ranging from 2.00% to 5.25% and final maturity occurring in 2031.

Linden Wind Energy Project – As of June 30, 2015, debt consists of revenue bonds with fixed interest rates between 4.00% and 5.92% and final maturity occurring in 2035.

Linden Wind Energy Project Revenue Bonds – On September 28, 2010, SCPPA issued $138.3 million of the Linden Wind Energy Project Revenue Bonds, consisting of $96.8 million of 2010 Series A Tax Exempt Bonds and $41.5 million of the Series B Taxable Build America Bonds, together the 2010 Bonds.

The 2010 Series B Bonds were issued as Build America Bonds that are "qualified bonds" under the provisions of the American Recovery and Reinvestment Act of 2009. The interest on these bonds will not be excluded from gross income for federal income purposes, but will be exempt from the State of California personal income taxes. As such, the Authority receives a cash subsidy from the United States Treasury up to 35% of the interest payable on the 2010 Series B Bonds which is applied to offset the interest costs of the 2010 Series B Bonds.

Southern Transmission System Project – Debt consists of refunding and subordinate refunding series bonds with fixed interest rates ranging from 0.20% to 6.125% and final maturities occurring in 2027.

Note 6 – Long-Term Debt (continued)

STS Project Refunding Bonds – On March 4, 2015, SCPPA issued $84,640,000 Transmission Project Revenue Bonds, 2015 Subordinate Refunding Series A and $28,925,000 Subordinate Series B (Taxable Bonds), together the $113,565,000 2015 A&B bonds. These fixed rate bonds were issued to redeem all of the outstanding $102,000,000 Transmission Project Subordinate Refunding Bonds, 2000 Series A; to terminate the 2000 Swap/Swaption; and to pay the costs of issuance of the STS 2015 A&B bonds. The refunding transaction generated a net present value savings of $954,453. This transaction resulted in a net loss for accounting purposes of $31.5 million.

In addition, on March 25, 2015, SCPPA issued $116,535,000 Transmission Project Revenue Bonds, 2015 Subordinate Refunding Series C Bonds. These fixed rate bonds were issued to advance refund all of the outstanding $125,000,000 Transmission Project Subordinate Refunding Bonds, 2008 Series B and to pay the costs of issuance of the STS 2015 Series C bonds. The refunding transaction generated a net present value savings of approximately $20.7 million. This transaction resulted in a net loss of accounting purposes of $20.8 million.

Windy Point/Windy Flats Project – As of June 30, 2015, debt consists of revenue bonds with fixed interest rates between 3.00% and 5.00% and final maturity occurring in 2030.

Mead Phoenix/Mead Adelanto Projects – Debt consists of revenue and refunding series bonds with variable interest and fixed interest rates. Fixed interest rates range from 1.115% and 5.15% with final maturities occurring in 2020.

Mead Phoenix/Mead Adelanto Refunding Bonds – On September 12, 2012, SCPPA issued Mead-Adelanto and Mead-Phoenix 2012 Series A and B Revenue Bonds (the "2012 Bonds") in the aggregate principal amount of $127.8 million, consisting of $79.4 million Mead-Adelanto 2012 Series A, $16.6 million Mead-Adelanto 2012 Series B (Taxable), $24.5 million Mead-Phoenix 2012 Series A, and $5.3 million Mead-Phoenix 2012 Series B (Taxable). These fixed rate bonds were issued to provide moneys, together with other available funds, to refund the outstanding Mead-Adelanto and Mead Phoenix Revenue Bonds, 2008 Series A and B (the "2008 Bonds"); to terminate the related interest rate swap agreement; and to pay the related cost of issuance of the 2012 Bonds. The transaction generated present value savings of over $1.97 million or 1.5% of refunded par for SCPPA and its members. This transaction resulted in a net loss for accounting purposes of $31.4 million. The true interest cost of the 2012 Bonds was 1.39%.

Natural Gas Projects – Debt consists of revenue bonds with fixed interest rates ranging from 4.73% to 6.03% and final maturities occurring in 2032.

Prepaid Natural Gas Project – Debt consists of revenue bonds with variable and fixed interest rates ranging from 5.00% to 5.25% and final maturity occurring in 2035.

Note 6 – Long-Term Debt (continued)

Premiums / Discounts– Unamortized premiums and discounts, net, which are included in the statements of net position as a component of long-term debt, are as follows (amounts in thousands):

Unamortized (Premium) Discount, Net	June 30, 2015 (Premium) Discount
Magnolia Power Project	$ (3,878)
Canyon Power Project	(6,517)
Apex Power Project	(14,077)
Hoover Uprating Project	(16)
Tieton Hydropower Project	(1,101)
Milford I Wind Project	(8,329)
Milford II Wind Project	(12,245)
Windy Point Project	(35,729)
Linden Wind Energy Project	(5,923)
Southern Transmission System Project	(60,013)
Mead-Phoenix Project	(2,035)
Mead-Adelanto Project	(8,474)
Prepaid Natural Gas Project No. 1	(2,847)
	$ (161,184)

Unamortized (Premium) Discount, Net	June 30, 2014 (Premium) Discount
San Juan Project	$ (1,481)
Magnolia Power Project	(5,034)
Canyon Power Project	(7,575)
Apex Power Project	(14,824)
Hoover Uprating Project	(32)
Tieton Hydropower Project	(1,166)
Milford I Wind Project	(9,578)
Milford II Wind Project	(14,305)
Windy Point Project	(41,530)
Linden Wind Energy Project	(6,882)
Southern Transmission System Project	(24,092)
Mead-Phoenix Project	(2,753)
Mead-Adelanto Project	(11,399)
Prepaid Natural Gas Project No. 1	(3,109)
	$ (143,760)

Note 6 – Long-Term Debt (continued)

Advance refundings – The Authority has established irrevocable escrow trusts with the proceeds from issuance of subordinate refunding bonds. These investments will be used to pay specified revenue bonds called at scheduled redemption dates.

Defeasance of debt – The Authority has defeased specified revenue bonds by placing the proceeds from the issuance of subordinate refunding bonds in irrevocable trusts to provide for all future debt service payments on the refunded bonds. The trust investments and related liability for bonds that are considered legally defeased are not included in the Authority's financial statements. At June 30, 2015 and 2014, $466.6 million and $378.4 million, respectively, of revenue bonds outstanding are considered legally defeased.

The refunded bonds constitute a contingent liability of the Authority only to the extent that cash and investments presently in the control of the refunding trustees are not sufficient to meet debt service requirements and are therefore excluded from the combined financial statements because the likelihood of additional funding requirements is considered remote.

Debt service – The scheduled debt service payments for future years ending June 30 are included in the table on the following page. The variable rates used for the PV 2008 Subordinate Refunding Series A and B Bonds were both 0.09%. The variable rates used for the MAG 2009-1 and MAG 2009-2 were 0.05% and 0.06%, respectively. All of the preceding variable rates were the rates at June 30, 2015. The variable rates are set by the bond-remarketing agent on a weekly basis based on economic conditions and bond ratings.

Note 6 – Long-Term Debt (continued)

Future principal and interest payments are as follows (amounts in thousands):

	GENERATION					GREEN POWER					
	Palo Verde	San Juan	Magnolia Power	Canyon Power Project	Apex Power Project	Hoover Uprating	Tieton Hydro-power	Milford I Wind	Milford II Wind	Windy Point	Linden Wind Energy
2016 Principal	$ 11,690	$ 21,590	$ 10,985	$ -	$ 9,335	$ 1,930	$ 840	$ 8,820	$ 5,530	$ 19,390	$ 3,670
2016 Interest	757	350	11,176	16,732	12,588	270	2,503	9,874	7,201	21,277	6,411
2017 Principal	12,030	21,345	11,470	6,735	9,375	2,030	870	9,175	5,795	20,145	3,820
2017 Interest	461	169	10,672	16,597	12,537	165	2,468	9,476	6,934	20,449	6,261
2018 Principal	12,410	-	7,230	7,005	9,435	2,135	910	9,615	6,065	21,045	3,970
2018 Interest	155	-	10,242	16,287	12,453	55	2,429	9,022	6,646	19,513	6,085
2019 Principal	-	-	7,560	7,355	9,545	-	950	10,085	6,370	22,020	4,170
2019 Interest	-	-	9,903	15,965	12,316	-	2,385	8,545	6,346	18,515	5,902
2020 Principal	-	-	7,925	7,645	9,710	-	1,000	10,570	6,665	23,040	4,335
2020 Interest	-	-	9,539	15,645	12,128	-	2,336	8,040	6,030	17,462	5,711
2021 - 2025 Principal	-	-	47,745	44,155	52,630	-	5,845	61,140	38,710	132,810	24,930
2021 - 2025 Interest	-	-	41,940	72,056	56,252	-	10,795	31,718	24,606	69,161	25,257
2026 - 2030 Principal	-	-	66,905	56,440	62,795	-	9,585	77,815	49,930	169,235	31,725
2026 - 2030 Interest	-	-	32,143	59,228	45,655	-	8,511	14,597	13,076	31,752	18,253
2031 - 2035 Principal	-	-	81,815	69,440	78,205	-	10,230	17,975	23,830	39,090	39,935
2031 - 2035 Interest	-	-	20,300	41,138	29,601	-	6,188	449	1,267	977	8,714
2036 - 2040 Principal	-	-	84,895	83,915	77,830	-	13,055	-	-	-	8,945
2036 - 2040 Interest	-	-	3,475	18,426	8,021	-	3,292	-	-	-	265
2041 - 2042 Principal	-	-	-	18,780	-	-	6,385	-	-	-	-
2041 - 2042 Interest	-	-	-	558	-	-	160	-	-	-	-
Principal	$ 36,130	$ 42,935	$ 326,530	$ 301,470	$ 318,860	$ 6,095	$ 49,670	$ 205,195	$ 142,895	$ 446,775	$ 125,500
Interest	$ 1,373	$ 519	$ 149,390	$ 272,632	$ 201,551	$ 490	$ 41,067	$ 91,721	$ 72,106	$ 199,106	$ 82,859

Note 6 – Long-Term Debt (continued)

	TRANSMISSION			NATURAL GAS			
	Southern Transmission System	Mead-Phoenix	Mead-Adelanto	Pinedale	Barnett	Prepaid Natural Gas	Total
2016 Principal	$ 53,085	$ 5,480	$ 17,690	$ 2,274	$ 5,326	$ 4,075	$ 181,710
2016 Interest	26,606	1,249	4,625	1,331	3,128	15,659	141,737
2017 Principal	53,650	5,515	17,985	2,249	5,266	4,275	191,730
2017 Interest	27,140	1,029	3,882	1,215	2,855	15,450	137,760
2018 Principal	54,315	5,660	18,450	1,980	4,640	4,605	169,470
2018 Interest	24,876	795	3,105	1,104	2,596	15,228	130,591
2019 Principal	56,100	5,875	19,185	1,770	4,150	5,385	160,520
2019 Interest	22,176	551	2,164	1,003	2,357	14,978	123,106
2020 Principal	49,005	6,030	19,995	1,627	3,818	6,445	157,810
2020 Interest	19,632	327	1,184	907	2,134	14,675	115,750
2021 - 2025 Principal	305,090	4,615	15,481	6,765	15,895	50,470	806,281
2021 - 2025 Interest	54,272	103	342	3,312	7,801	66,563	464,178
2026 - 2030 Principal	89,481	-	-	5,301	12,474	89,970	721,656
2026 - 2030 Interest	6,590	-	-	1,595	3,767	48,534	283,701
2031 - 2035 Principal	-	-	-	2,797	6,593	126,445	496,355
2031 - 2035 Interest	-	-	-	247	582	20,028	129,491
2036 - 2040 Principal	-	-	-	-	-	17,945	286,585
2036 - 2040 Interest	-	-	-	-	-	453	33,932
2041 - 2042 Principal	-	-	-	-	-	-	25,165
2041 - 2042 Interest	-	-	-	-	-	-	718
Principal	$ 660,726	$ 33,175	$ 108,786	$ 24,763	$ 58,162	$ 309,615	$ 3,197,282
Interest	$ 181,292	$ 4,054	$ 15,302	$ 10,714	$ 25,220	$ 211,568	$ 1,560,964

Note 7 – Notes Payable and Other Liabilities

Notes payable and other liabilities consist mainly of Palo Verde Participants' overbillings from prior periods; an allowance for future major maintenance expenses for the Magnolia Power Project; and swap-related transaction fees received in the Mead Adelanto Project. The notes payable held in the Palo Verde Project are invested in a guaranteed investment contract (GIC) that will mature in June 2017. The GIC is unsecured, bears an interest rate at 4.97%, and is paid out in monthly installments of $0.6 million. On June 30, 2015, the remaining balance of the GIC is $14.5 million.

The three-year suspension of the Mead Adelanto 2007 CMS (the CMS Swap) in November 2008 netted a compensation of $4.1 million. In June 2010, the suspension was extended to June 2018 for a net compensation of $5.0 million. The total deferred balance of the CMS Swap is $1.2 million as of June 30, 2015. (See Note 5).

Notes payable and other liabilities rollforward (amounts in thousands):

Description	June 30, 2014	Additions	Payments/ Amortization	Amortization of Surplus Fund	June 30, 2015
PV prior year overbillings	$ 20,066	$ -	$ (6,735)	$ 393	$ 13,724
MPP major maintenance	8,622	4,661	(131)	-	13,152
Mead Adelanto 2007 Swap suspension	2,477	-	(629)	-	1,848
Net pension liability	-	874	-	-	874
	$ 31,165	$ 5,535	$ (7,495)	$ 393	$ 29,598

Note 8 – Advances from Participants

Advances from participants consist mainly of billings to participants related to acquisition, capital drilling, and inventory wherein the matching operating expenses will be recognized at a future date. Also, and specific only to the Natural Gas Pinedale Project, advances held by the project are funds from LADWP and TID, both owners independent of SCPPA, and are for their share of operating costs and capital expenditures pursuant to their respective Agency Agreements.

Note 8 – Advances from Participants (continued)

Advances from participants' rollforward (amounts in thousands):

Description		June 30, 2014		Activity		June 30, 2015
San Juan advances from participants	$	9,082	$	250	$	9,332
MAG advances from participants		22,429		(4,633)		17,796
Canyon Power advances from participants		2,225		-		2,225
Apex advances from participants		2,500		(2,500)		-
Tieton advances from participants		202		-		202
Milford I advances from participants		250		-		250
Milford II advances from participants		250		-		250
Windy Point advances from participants		1,000		-		1,000
Linden Wind Energy advances from participants		2,004		-		2,004
NG Pinedale advances from participants		29,306		(9,444)		19,862
NG Barnett advances from participants		10,447		(677)		9,770
Ormat advances from participants		857		-		857
MWD advances from participants		500		-		500
Ameresco advances from participants		400		-		400
PDF advances from participants		65		6,420		6,485
SCPPA Building advances from participants		282		(149)		133
Don A Campbell Wild Rose advances from participants		-		480		480
Columbia Solar 2 advances from participants		-		538		538
	$	81,799	$	(9,715)	$	72,084

Note 9 – Net Position

The Authority's billing amounts to the participants are determined by its Board of Directors and are subject to review and approval by the participants. Billings to participants are designed to recover "costs" as defined by the power sales, natural gas sales, and transmission service agreements. The billings are structured to systematically provide for debt service requirements, operating funds, and reserves in accordance with these agreements. The accumulated difference between billings and the Authority's expenses calculated in accordance with accounting principles generally accepted in the United States of America are presented as Net Position. It is intended that this difference will be recovered in the future through billings for repayment of principal on the related bonds.

Note 9 - Net Position (continued)

Net position is comprised of the following (in thousands):

	June 30, 2014	Fiscal Year 2014 Activity	June 30, 2014	Fiscal Year 2015 Activity	June 30, 2015
GAAP items not included in billings to participants					
Depreciation of plant	$ (1,522,366)	$ (97,964)	$ (1,620,330)	$ (106,590)	$ (1,726,920)
Nuclear fuel amortization	(5,860)	-	(5,860)	-	(5,860)
Decommissioning expense	(218,831)	(5,679)	(224,510)	(10,857)	(235,367)
Amortization of bond discount, debt issue costs, and loss on refundings	(796,648)	(10,009)	(806,657)	(8,928)	(815,585)
Interest expense	(55,781)	833	(54,948)	53	(54,895)
Loss on defeasance of bonds	(85,827)	-	(85,827)	-	(85,827)
Derivatives and related charges	(39,907)	395	(39,512)	28,364	(11,148)
Pension expense	-	-	-	(730)	(730)
Bond requirements included in billings to participants					
Operations and maintenance, net of investment income	135,471	(53,424)	82,047	(62,911)	19,136
Costs of acquisition of capacity	6,479	(1,496)	4,983	(1,570)	3,413
Billings to amortize costs recoverable	382,050	-	382,050	-	382,050
Reduction in debt service billings due to transfer of excess funds	(90,020)	-	(90,020)	-	(90,020)
Principal repayments	1,787,136	165,388	1,952,524	177,424	2,129,948
Withdrawal of funds	-	(24,821)	(24,821)	-	(24,821)
Other	269,522	10,645	280,167	20,421	300,588
	(234,582)	(16,132)	(250,714)	34,676	(216,038)
Projects' Stabilization Fund net position	127,583	24,444	152,027	4,560	156,587
	$ (106,999)	$ 8,312	$ (98,687)	$ 39,236	$ (59,451)

Note 10 - Pension Plans

Plan descriptions - All qualified permanent and probationary employees are eligible to participate in SCPPA's Miscellaneous Employee Pension Plans, cost-sharing multiple employer defined benefit pension plans administered by the California Public Employees' Retirement System (CalPERS). Benefit provisions under the Plans are established by State statute and SCPPA resolution. CalPERS issues publicly available reports that include a full description of the pension plans regarding benefit provisions, assumptions and membership information that can be found on the CalPERS website.

Benefits provided - CalPERS provides service retirement and disability benefits, annual cost of living adjustments and death benefits to plan members, who must be public employees and beneficiaries. Benefits are based on years of credited service, equal to one year of full time employment. Members with five years of total service are eligible to retire at age 50 with statutorily reduced benefits. All members are eligible for non-duty disability benefits after 10 years of service.

Note 10 – Pension Plans (continued)

The death benefit is one of the following: the Basic Death Benefit, the 1957 Survivor Benefit, or the Optional Settlement 2W Death Benefit. The cost of living adjustments for each plan are applied as specified by the Public Employees' Retirement Law.

The Plans' provisions and benefits in effect at June 30, 2015, are summarized as follows:

	Prior to January 1, 2013	On or after January 1, 2013
Hire date		
Benefit formula	2.7% @ 55	2% @ 62
Benefit vesting schedule	5 years service	5 years service
Benefit payments	monthly for life	monthly for life
Retirement age	50 - 55	52 - 67
Monthly benefits, as a % of eligible compensation	2.0% to 2.7%	1.0% to 2.5%
Required employee contribution rates	8%	6.5%
Required employer contribution rates	19.6%	6.7%

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

For the year ended June 30, 2015, the contributions recognized as part of pension expense for the Plans were $257,104.

Pension liabilities, pension expenses and deferred outflows / inflows of resources related to pensions – As of June 30, 2015, SCPPA reported a net pension liability of $873,857 for its proportionate share of the net pension liability. SCPPA's net pension liability for each Plan is measured as the proportionate share of the net pension liability. The net pension liability of each of the Plans is measured as of June 30, 2014, and the total pension liability for each Plan used to calculate the net pension liability was determined by an actuarial valuation as of June 30, 2013 rolled forward to June 30, 2014 using standard update procedures. SCPPA's proportion of the net pension liability was based on a projection of SCPPA's long-term share of contributions to the pension plans relative to the projected contributions of all participating employers, actuarially determined. SCPPA's proportionate share of the net pension liability for the Plans was 0.01404% as of June 30, 2014 and 2013.

Note 10 – Pension Plans (continued)

For the year ended June 30, 2015, SCPPA recognized pension expense of $238,141. At June 30, 2015, SCPPA reported deferred outflows of resources and deferred inflows of resources related to pensions from the following sources:

For the Period Ended June 30,	2016	$	(17,412)
	2017		(17,412)
	2018		(24,290)
	2019		(51,803)
		$	(110,917)

$257,104 reported as deferred outflows of resources related to contributions subsequent to the measurement date will be recognized as a reduction of the net pension liability in the year ended June 30, 2016. Other amounts reported as deferred outflows of resources and deferred inflows of resources related to pensions will be recognized as pension expense as follows:

Actuarial assumptions – The total pension liabilities in the June 30, 2013 actuarial valuations were determined using the following actuarial assumptions:

Valuation Date	June 30, 2013
Measurement Date	June 30, 2014
Actuarial Cost Method	Entry -Age Normal
Actuarial Assumptions:	
Discount Rate	7.50%
Inflation	2.75%
Payroll Growth	3.0%
Projected Salary Increase	3.3% - 14.2% (1)
Investment Rate of Return	7.5% (2)
Mortality	Derived using CalPERS' Membership Data

(1) Depending on age, service and type of employment
(2) Net pension plan investment expenses, including inflation

The underlying mortality assumptions and all other actuarial assumptions used in the June 30, 2013 valuation were based on the results of a January 2014 actuarial experience study for the period 1997 to 2011. Further details of the Experience Study can be found on the CalPERS website.

Note 10 – Pension Plans (continued)

Discount rate – The discount rate used to measure the total pension liability was 7.50% for the Plans. To determine whether the municipal bond rate should be used in the calculation of a discount rate for the Plans, CalPERS stress tested plans that would most likely result in a discount rate that would be different from the actuarially assumed discount rate. Based on the testing, none of the tested plans run out of assets. Therefore, the current 7.50 percent discount rate is adequate and the use of the municipal bond rate calculation is not necessary. The long term expected discount rate of 7.50 percent will be applied to all plans in the Public Employees Retirement Fund (PERF). The stress test results are presented in a detailed report that can be obtained from the CalPERS website.

According to paragraph 30 of Statement 68, the long-term discount rate should be determined without reduction for pension plan administrative expense. The 7.50 percent investment return assumption used in this accounting valuation is net of administrative expenses. Administrative expenses are assumed to be 15 basis points. An investment return excluding administrative expenses would have been 7.65 percent. Using this lower discount rate has resulted in a slightly higher total pension liability and net pension liability. CalPERS checked the materiality threshold for the difference in calculation and did not find it to be a material difference.

CalPERS is scheduled to review all actuarial assumptions as part of its regular Asset Liability Management (ALM) review cycle that is scheduled to be completed in February 2018. Any changes to the discount rate will require Board action and proper stakeholder outreach. For these reasons, CalPERS expects to continue using a discount rate net of administrative expenses for GASB 67 and 68 calculations through at least the 2017-18 fiscal year. CalPERS will continue to check the materiality of the difference in calculation until such time as CalPERS has changed its methodology.

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

In determining the long-term expected rate of return, CalPERS took into account both short-term and long-term market return expectations as well as the expected pension fund cash flows. Using historical returns of all the funds' asset classes, expected compound returns were calculated over the short-term (first 10 years) and the long-term (11-60 years) using a building-block approach. Using the expected nominal returns for both short-term and long-term, the present value of benefits was calculated for each fund.

Note 10 – Pension Plans (continued)

The expected rate of return was set by calculating the single equivalent expected return that arrived at the same present value of benefits for cash flows as the one calculated using both short-term and long-term returns. The expected rate of return was then set equivalent to the single equivalent rate calculated above and rounded down to the nearest one quarter of one percent.

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

Asset Class	New Strategic Allocation	Real Return Years 1 - 10(a)	Real Return Years 11+ (b)
Global Equity	47.0%	5.25%	5.71%
Global Fixed Income	19.0%	0.99%	2.43%
Inflation Sensitive	6.0%	0.45%	3.36%
Private Equity	12.0%	6.83%	6.95%
Real Estate	11.0%	4.50%	5.13%
Infrastructure and Forestland	3.0%	4.50%	5.09%
Liquidity	2.0%	-0.55%	-1.05%
Total	100.0%		

(a) An expected inflation of 2.5% used for this period
(b) An expected inflation of 3.0% used for this period

Sensitivity of the proportionate share of the net pension liability to changes in the discount rate – The following presents SCPPA's proportionate share of the net pension liability for the Plans, calculated using the discount rate for each Plan, as well as what SCPPA's proportionate share of the net pension liability would be if it were calculated using a discount rate that is 1-percentage point lower or 1-percentage point higher than the current rate:

1% Decrease	6.50%
Net Pension Liability	$ 1,389,989
Current Discount Rate	7.50%
Net Pension Liability	$ 873,857
1% Increase	8.50%
Net Pension Liability	$ 445,517

Note 10 – Pension Plans (continued)

Pension plan fiduciary net position – Detailed information about each pension plan's fiduciary net position is available in the separately issued CalPERS financial reports.

Payable to the pension plan – At June 30, 2015, SCPPA did not have an outstanding amount of contributions payable to the pension plan for the year ended June 30, 2015.

Note 11 – Commitments and Contingencies

Public benefits – The members continue to collect the public benefit charge through existing rate structures and have instituted programs to benefit their customers including conservation and energy efficiency programs, public educational programs, research and development, and low income rate subsidies, totaling a combined $1.7 billion since their inception in 1997. The decisions on how these funds are allocated are made by the local governing authority, in most cases this is the city council.

Executive action and state legislation – The California Legislature is considering several bills that would affect the electric utility industry. In general, these bills build upon prior efforts and would provide for long-term greenhouse gas emission reduction standards and greater investment in energy-efficient and environmentally friendly generation alternatives through more stringent renewable resource portfolio standards. The following is a brief summary of certain of these bills and related background:

Greenhouse gas emissions – Executive Order S-3-05 placed an emphasis on efforts to reduce greenhouse gas emissions by establishing statewide greenhouse gas reduction targets. The targets are: (i) a reduction to 2000 emission levels by 2010; (ii) a reduction to 1990 levels by 2020; and (iii) a reduction to 80% below 1990 levels by 2050. The Executive Order also called for the California Environmental Protection Agency (the "EPA") to lead an effort to examine the impacts of climate change on California and develop strategies and mitigation plans to achieve the targets. In addition, Executive Order S-06-06 directs the State of California to meet a 20% biomass utilization target within the renewable generation targets of 2010 and 2020 for the contribution to greenhouse gas emission reduction. Executive Order B-30-15 was issued on April 29, 2015 that would set a new interim statewide greenhouse gas emissions reduction target to 40% below 1990 levels by 2030 en route towards achieving the 2050 emissions reduction target. The interim goal was since incorporated into pending legislation, SB 32 (Pavley), currently being considered in the California State Assembly.

Note 11 – Commitments and Contingencies (continued)

Assembly Bill 32, the Global Warming Solutions Act of 2006 (the GWSA) became effective as law on January 1, 2007. The GWSA prescribed a statewide cap on global warming pollution with a goal of reaching 1990 greenhouse gas emission levels by 2020. In addition, the GWSA establishes an annual mandatory reporting program for all investor-owned utilities (IOUs), local publicly-owned electric utilities ("POUs"), and other load-serving utilities (electric utilities providing energy to end-use customers) to inventory and report greenhouse gas emissions to the California Air Resources Board (CARB) and requires CARB to adopt regulations for significant greenhouse gas emission sources (allowing CARB to design a cap-and-trade system), and gives CARB the authority to enforce such regulations beginning in 2012. CARB adopted a "scoping plan" to reduce greenhouse gas emissions which included a mixed approach of market structures, regulation, fees and voluntary measures. The scoping plan included a cap-and-trade system that covers 85% of all California greenhouse gas emissions. In August 2011, CARB revised the scoping plan in response to litigation. The revised scoping plan continued to include a cap-and-trade program. The scoping plan is required to be updated every five years and the updated scoping plan was approved on May 22, 2014.

On October 20, 2011, CARB adopted a regulation, which was approved on December 13, 2011, implementing a cap-and-trade system. The cap-and-trade regulation became effective on January 1, 2012, and emission compliance obligations under the cap-and-trade regulation began on January 1, 2013. The cap-and-trade program is the largest of its type in the United States and covers sources accounting for 85% of California's greenhouse gas emissions.

The cap-and-trade program is being implemented in phases. The first phase of the program was implemented from January 1, 2013 to December 31, 2014 and introduces a hard emissions cap that covers emissions from electricity generators, electricity importers, and large industrial sources emitting more than 25,000 metric tons of carbon dioxide-equivalent greenhouse gases per year. In 2015, the program was expanded to cover emissions from transportation fuels, natural gas, propane, and other fossil fuels. The cap will decline each year until the end of the program, which is currently set as December 2020.

The cap-and-trade program includes the distribution of carbon allowances equal to the annual emissions cap. Initially, as part of the transition process, most of the carbon allowances will be distributed for free. Quarterly auctions for additional allowances began in November 2012. IOUs, as well as POUs that sell electricity into the ISO markets (including some Project Participants), will be required to auction their allowances. They will then need to purchase allowances to meet their compliance obligations, and use the remaining from the sale of their allocated allowances for the benefit of their rate payers.

Note 11 – Commitments and Contingencies (continued)

On January 1, 2014, the California cap and trade program was linked to the equivalent program in Quebec, Canada as part of the Western Climate Initiative. The Western Climate Initiative is a regional effort consisting of California and four Canadian provinces (Quebec, British Colombia, Ontario, and Manitoba), which have established a greenhouse gas reduction trading framework.

On April 25, 2014, CARB adopted various changes to the cap-and-trade program, including provisions relating to the electricity sector such as "safe harbor" provisions under the "resource shuffling" prohibition. These changes became effective on July 1, 2014. Additional amendments are expected to be considered through 2016, including regarding post-2020 programmatic issues and any needed changes to comply with the federal Clean Power Plan.

The Authority and the Project Participants are unable to predict at this time the full impact of the cap-and-trade program on the Project Participants' respective electric utilities or on the electric utility industry in general. However, the Project Participants could be adversely affected if the carbon emissions of their respective resource portfolios are in excess of the allowances administratively allocated to them, and they are required to purchase allowances on the market to cover their emissions.

Senate Bill 1368 (SB 1368) became effective as law on January 1, 2007. It provides for an emission performance standard, restricting new investments in baseload fossil fuel electric generating resources that exceed the rate of greenhouse gas emissions for existing combined-cycle natural gas baseload generation. SB 1368 allows the California Energy Commission (CEC) to establish a regulatory framework to enforce the greenhouse gas emission performance standard for POUs such as the Project Participants. In December 2011, the CEC decided to undertake a review of these regulations to ensure there is adequate review of investments in facilities that do not meet the emission performance standard. The CEC issued its Proposed Final Conclusions in the EPS proceeding on April 5, 2013. The proposed changes and any future changes to the EPS regulations may impact the Project Participants.

In addition, Assembly Bill 1925 signed into law on September 26, 2006, requires the CEC to develop a cost effective strategy for the geologic sequestration and management of industrial carbon dioxide.

On March 19, 2014, the CEC issued its Final Conclusions in the EPS proceeding. The CEC proposed to expand the public notice requirement so that a publicly-owned utility would have to post a notice of a public meeting at which its governing board would consider any expenditures over $2.5 million to meet environmental regulatory requirements at a non-EPS compliant baseload facility. The CEC further proposed to require each POU to file an annual notice identifying all investments over $2.5 million that it anticipates making during the subsequent 12 months on non-EPS compliant baseload facilities to comply with environmental regulatory requirements. This requirement would be waived for any POU that has entered into a binding agreement to divest within five years of all baseload facilities exceeding the EPS. The CEC did not propose to lower the EPS. Further, by letter from the CPUC to the CEC, the CPUD expressed its view that the EPS not be lowered.

Note 11 – Commitments and Contingencies (continued)

A final regulatory package was unanimously adopted at the CEC's June 18, 2014 business meeting. The adopted regulations had limited changes to the proposed POU reporting requirements. CEC staff have also since confirmed that the $2.5 million threshold applies to an individual investment by each utility – not the combined investment of all participants in a project. These changes and any future changes to the EPS regulations may impact Authority members.

Energy procurement and efficiency reporting – Senate Bill 1037, which was signed into law on September 29, 2005, requires that each POU, including the Project Participants, prior to procuring new energy generation resources, first acquire all available energy efficiency, demand reduction, and renewable resources that are cost effective, reliable and feasible, then report annually to its customers and to the CEC its investment in energy efficiency and demand reduction programs. Each Project Participant has complied with such reporting requirements.

Assembly Bill 2021, signed on September 29, 2006, requires that POUs establish, report, and explain the basis of the annual energy efficiency and demand reduction targets every three years for a ten-year horizon since 2007. Each of the Project Participants has complied with this reporting requirement.

Pending legislation in the California State Legislature, most notably AB 1330 (Bloom), would set individual utility energy efficiency procurement targets.

Renewable Portfolio Standard (RPS) – Senate Bill X1 2 (SBX1 2), the "California Renewable Energy Resources Act," was signed into law on April 12, 2011. SBX1 2 codifies the RPS target for retail electricity sellers to serve 33% of their loads with eligible renewable energy resources by 2020 as provided in Executive Order S-14-08. As enacted, SBX 1 2 makes the requirements of the RPS program applicable to POUs. The governing boards of POUs are responsible for implementing the requirements and each POU is required to adopt and implement a renewable energy resources procurement plan. The plan must require the utility to procure a minimum quantity of electricity product from eligible renewable energy resources, including renewable energy certificates ("RECs"), as a specified percentage of total kilowatt hours sold to the utility's retail end-use customers to achieve specific targets. Certain enforcement authority with respect to POUs is given to the CEC and CARB, including authority to impose penalties.

SBX1 2 grandfathers any facility approved by the governing board of a POU prior to June 1, 2010 for procurement to satisfy renewable energy procurement obligations adopted under prior law if the facility is a "renewable electrical generation facility" as defined in the bill (subject to certain restrictions). The CEC has developed detailed rules to implement SXB1 2 and on June 12, 2013, the CEC adopted regulations for the enforcement of the RPS program requirements for POUs.

Note 11 – Commitments and Contingencies (continued)

In connection with the implementation of SBX1 2, the CEC is responsible for certifying the electric generation facilities as "eligible renewable energy resources" for purposes of the RPS program and has adopted guidelines for this purpose that identifies the requirements, conditions and process for certification of facilities as eligible renewable energy resources. The current guidelines identify bio-methane as an eligible renewable energy resource. Under these guidelines adopted on April 30, 2013, utilities that procure bio-methane were required to reapply for certification of the generating facilities that use bio-methane.

On January 5, 2015, Governor Jerry Brown proposed three major climate goals to be completed within the next 15 years: 1) increase 33% to 50% California's electricity derived from renewables; 2) reduce current petroleum use in cars and trucks by up to 50%; and 3) increase by 50% the efficiency of existing buildings and make heating fuels cleaner. A number of bills were subsequently introduced in the State Legislature that, if adopted, would, among other things, implement the climate goals announced by the Governor. As expected, the proposed bills would increase the State's Renewables Portfolio Standard from 33% to 50% (SB 350 (de Leon) and AB 645 (Williams)). The Authority and the Project Participants are unable to predict the outcome or potential impacts of any possible legislation at this time.

Solar power – Senate Bill 1 (also known as the California Solar Initiative), which was signed into law on August 21, 2006, requires POUs, including the Project Participants, to establish a program supporting the stated goal of the legislation to install 3,000 MW of photovoltaic energy in California. POUs are also required to establish eligibility criteria in collaboration with the CEC for the funding of solar energy systems receiving ratepayer-funded incentives. Certain reporting requirements also have to be met by the POUs. Each of the Project Participants has established programs in accordance with the requirements of the California Solar Initiative.

The effect of these developments in the California energy markets on the Project Participants cannot be fully ascertained at this time. Also, volatility in energy price in California may return due to a variety of factors which affect both the supply and demand for electric energy in the western United States. This price volatility may contribute to greater volatility in the revenues of their respective electric systems from the sale (and purchase) of electric energy and, therefore, could materially affect each Project Participant's financial condition. Each Project Participant undertakes resource planning, risk management activities, and manages its resource portfolio to mitigate such price volatility and spot market rate exposure.

Note 11 – Commitments and Contingencies (continued)

Federal energy legislation – Under the federal Energy Policy Act of 2005 (EPAct 2005), FERC was given refund authority over municipal utilities if they sell into short-term markets, like the ISO markets, and sell eight million MWhs or more of electric energy on an annual basis. In addition, FERC was given authority over the behavior of market participants and the authority to issue permits to construct or modify transmission facilities located in a national interest electric transmission corridor. EPAct 2005 requires the creation of an electric reliability organization (ERO) to establish and enforce, under FERC supervision, mandatory reliability standards to increase system reliability and minimize blackouts. Failure to comply with such mandatory standards exposes a utility to significant fines and penalties by the ERO.

NERC Reliability Standards – EPAct 2005 required FERC to certify an ERO to develop mandatory and enforceable reliability standards, subject to FERC review and approval. On February 3, 2006, FERC issued Order 672, which certified the North American Electric Reliability Corporation (NERC) as the ERO. Many reliability standards have since been approved by FERC. FERC Order 693 further provided ERO and Regional Entities (entities to which NERC has delegated enforcement authority through an agreement approved by FERC) with the discretion to calculate a penalty without collecting the penalty if circumstances warrant.

Other legislation – Congress has considered and is considering numerous bills addressing domestic energy policies and various environmental matters, including bills relating to energy supplies and development (such energy efficiency requirements and expedited permitting for natural gas drilling and hydropower projects), climate change, physical and cyber security, and water quality. Many of these bills, if enacted into law, could have a material impact on the Authority, the Project Participants, and the electric utility industry in general. The Authority and the Project Participants are unable to predict the outcome or potential impacts of any possible legislation at this time.

Environmental issues – Electric utilities are subject to continuing environmental regulation. Federal, state and local standards and procedures which regulate the environmental impact of electric utilities are subject to change. There is no assurance that any Authority or Project Participant facility or project will remain subject to the laws and regulations currently in effect, will always be in compliance with future laws and regulations, or will always be able to obtain all required operating permits. The Authority is unable to predict the outcome of these legal and legislative challenges at this time.

Note 11 – Commitments and Contingencies (continued)

Greenhouse Gas Regulations Under the Clean Air Act – The United States Environmental Protection Agency (the "EPA") has taken steps to regulate greenhouse gas emissions under existing law. In 2009, the EPA issued a final "endangerment finding," in which it declared that the weight of scientific evidence requires a finding that six identified greenhouse gases, namely, carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride, cause global warming, and that global warming endangers public health and welfare. The final rule for the "endangerment finding" was published in the Federal Register on December 15, 2009. As a result of this finding, the EPA considered it was authorized to issue regulations limiting carbon dioxide emissions from, among other things, stationary sources such as electric generating facilities, under the federal Clean Air Act.

The "Tailoring Rule," published in the Federal Register on June 3, 2010, states that greenhouse gas emissions will be regulated from large stationary sources, including electric generating facilities, if the sources emit more than the specified threshold levels of tons per year of carbon dioxide. Large sources, with the potential to emit in excess of the applicable threshold, will be subject to the major source permitting requirements under the Clean Air Act. Permits would be required in order to construct, modify, and operate facilities exceeding the emissions threshold. The endangerment finding and the Tailoring Rule have been challenged in court, but were upheld on June 26, 2012. The appealed petition for rehearing was denied on December 2012. Legislation has been introduced in the United States Congress that would repeal the EPA's endangerment finding or otherwise prevent the EPA from regulating greenhouse gases as air pollutants.

On September 22, 2009, the EPA issued the final rule for mandatory monitoring and annual reporting of greenhouse gas emissions from various categories of facilities, including fossil fuel suppliers, industrial gas suppliers and direct greenhouse emitters such as electric generating facilities and industrial processes. This rule does not require controls or limits on emissions, but required data collection to begin on January 1, 2010. The Project Participants are complying with the data collection and reporting requirement to which they are subject. Such data collection and reporting lays the foundation for controlling and reducing greenhouse gas emission in the future, whether by way of the EPA regulation under existing Clean Air Act authority or under a new climate change federal law.

Pursuant to a December 23, 2010 settlement agreement, the EPA proposed on April 13, 2012 to establish New Source Performance Standards limiting carbon dioxide emissions from fossil-fuel fired electric generating units. In response to a June 25, 2013 Presidential Memorandum, the EPA rescinded the April 13, 2012 proposal and re-proposed standards that they stated would apply only to new facilities, not reconstructed or modified facilities. The EPA is required by the Presidential Memorandum to propose by June 1, 2014, and finalize by June 1, 2015, standards, regulations, or guidelines that address carbon pollution from modified, reconstructed and existing power plants.

Note 11 – Commitments and Contingencies (continued)

On June 2, 2014, the EPA released its "Clean Power Plan" proposal for both existing and modified or reconstructed power plants as contemplated by a Presidential Memorandum. The proposed rule is designed to reduce carbon (CO_2) emissions from the power sector by 30% on average nationwide by 2030, as compared to 2012 levels. Under the proposal, the EPA will set different interim (2024) and final (2030) emissions targets for each state based on overall CO_2 emissions and the amount of electricity generated in the state. It was proposed that state emission targets may be met in a combination of ways, including through a "Best System of Emissions Reduction," which may include coal plant efficiency upgrades, switching from coal to natural gas, and by improving energy efficiency or promoting renewable energy. In the event a state fails to develop a satisfactory implementation plan, the EPA may impose a federal implementation plan instead.

The Authority submitted comments to the EPA on November 25, 2014 and joined in support of *comments also filed jointly by the "California Utilities" prior to the December 1, 2014 comment deadline.* The Authority's comments outlined potential issues and offered recommendations on how to improve the proposed rule so as not to compromise electric reliability for customers.

The EPA informally released the final set of "Clean Power Plan" rules on August 3, 2015. The Authority is currently reviewing the thousands of pages of associated materials for the rulemaking, along with outside expert regulatory counsel hired specifically for assistance with this rulemaking, to assess the final rule's impacts.

A number of lawsuits have been filed challenging the proposed and final rules and seeking to prevent the EPA from moving forward to implement the proposed Clean Power Plan. Additional legal and legislative challenges are also expected.

The Authority and the Project Participants are unable to predict the outcome of these challenges to the EPA's endangerment finding and subsequent rulemaking or the effect that any final rules promulgated by the EPA regulating greenhouse gas emissions from electric generating units and other stationary sources would have on the Authority's projects or the Project Participants and their respective electric systems.

National Ambient Air Quality Standards – The Clean Air Act requires that the EPA establish National Ambient Air Quality Standards (NAAQS) for certain air pollutants. Once NAAQS have been established, each state must identify areas that do not meet the EPA standard ("non-attainment areas") and develop regulatory measures in its state implementation plan to reduce or control the emissions of that air pollutant in order to meet the applicable standard and become an "attainment area". A proposal to lower the NAAQS for ozone was submitted and withdrawn and the EPA resumed the process of issuing non-attainment designations for the ozone NAAQS under the standard set in 2008. These developments may result in stringent permitting processes for new sources of emissions and additional state restrictions on existing sources of emissions. EPA is under court order to issue a final rule by October 1, 2015.

Note 11 – Commitments and Contingencies (continued)

Mercury and Air Toxic Standards ("MATS") – On December 16, 2011, the EPA signed a rule establishing new standards to reduce air pollution from coal- and oil-fired power plants under sections 111 (new source performance standards) and 112 (toxics program) of the Clean Air Act. The EPA updated the MATS emission limits on November 30, 2012 and again on March 28, 2013 and is currently reconsidering certain aspects of the regulation. Power plants have up to four years to meet these standards. While many plants meet some or all of these new standards, some plants will be required to install new equipment to meet the standards. The Project Participants purchase power from coal-fired power stations that may be affected by these new rules; and may be exposed to increased costs. The Supreme Court has since remanded the rulemaking back to a lower court because the EPA misinterpreted Clean Air Act Section 112 when it failed to consider compliance costs in regulating mercury from power plants. Filings in that case are due September 10, 2015.

Other proposals – The EPA has proposed regulations relating to the Coal Combustion Residuals such as ash; Cooling Water Intake Structures at certain existing power plants in order to reduce the number of fish and other aquatic organisms that are trapped against intake screens or drawn into the generating unit; and setting technology-based effluent limitations guidelines and standards for metals and other pollutants in wastewater discharged from steam electric power plants. These regulations, when finalized could increase the cost of power the Project Participants purchase from coal-fired units.

The EPA was required to take final action on a rule regulating coal combustion residuals by December 19, 2014 under a consent decree reached with a dozen environmental organizations. The EPA announced the final CCR rule on that day; it allows for beneficial use of coal ash under Subtitle D as expected. The EPA formally noticed the final rule in April 2015, which becomes effective on October 19, 2015; the definition of "CCR landfill" now includes "coal" (so other non-coal mines that receive utility coal ash may qualify as CCR landfills), and clarifies that when groundwater contamination from an unlined CCR surface impoundment exceeds an applicable water standard, the owner / operator may choose to retrofit the unit instead of closing it. Congress is considering legislation that would make further refinements to the rule.

Other factors – The electric utility industry in general has been, or in the future may be, affected by a number of other factors which could impact the financial condition and competitiveness of many electric utilities and the level of utilization of generating and transmission facilities. Such factors, including those discussed above, could have an adverse effect on the financial condition of any given electric utility and likely will affect individual utilities in different ways.

The Authority is unable to predict what impact such factors will have on the business operations and financial condition of its members but the impact could be significant. Extensive information on the electric utility industry is available from the legislative and regulatory bodies and other sources in the public domain.

Note 11 – Commitments and Contingencies (continued)

Nuclear spent fuel and waste disposal – Under the Nuclear Waste Policy Act, the Department of Energy (DOE) was to develop the facilities necessary for the storage and disposal of spent fuel and to have the first such facility in operation by 1998. DOE collected a fee of 0.1 cents/kwh of electric generation from the nuclear plant operators to fund the development and operation of the disposal facility.

In July 2002, a measure was signed into law designating the Yucca Mountain, in the state of Nevada, as the nation's high-level nuclear waste repository. This meant that the DOE could then file a construction and operation plan for the Yucca Mountain with the Nuclear Regulatory Commission (NRC). Due to a series of setbacks including scientific challenges by the National Academy of Science, falsified research data by consultants, and delays in submitting the construction application to the NRC, the operation date of the repository was pushed back several times.

In June 2008, the DOE submitted to the NRC a license application to construct the repository. In 2009, the federal government, under the new administration, decided to cut off all the appropriated funds for the development of the repository at the Yucca Mountain, at the urging of the Congress, except a small budget allocation for the closing of the project. The DOE subsequently submitted a request to the NRC to withdraw the license application. The withdrawal request was denied by the NRC due to a lack of valid reasons. Concurrently, an independent commission was formed by the DOE to find a solution for the nuclear waste disposition that would include Yucca Mountain among the different options. There are questions among utilities, as well as public utility commissions nationwide, about the continued collection of disposal fees by the DOE for the Nuclear Waste Fund recognizing that there is a lack of spent fuel disposal policy from the federal government. After further contest by the Public Utility Commissions of several states as well as the nuclear operators, the DOE suspended the collection of the 0.1 cents/kwh nuclear waste fee effective May 16, 2014.

The Palo Verde Operating Agent, on behalf of the co-owners, has litigated the DOE to recover the costs of storing spent fuel at Palo Verde because the DOE failed to honor the contract to remove and dispose of spent fuel as scheduled. In 2010, the federal court ruled in favor of Palo Verde and granted a compensation of $30.2 million which covered costs incurred up to 2006. The Authority's share of the settlement was $1.8 million. Palo Verde continues to pursue cost recovery through the DOE as additional spent fuel related expenses are accumulated for the continued operation of the plant. In 2012, Palo Verde filed a claim of $59 million for costs associated with the storage of spent fuel at the plant site for the period 2007-2011. Settlement was reached with the DOE for $57.4 million of which the Authority's share is $3.4 million. In June 2015, the Authority received a payment in the amount of $2.5 million for its share of the settlement with the DOE.

Note 11 – Commitments and Contingencies (continued)

The spent fuel storage in the wet pool at Palo Verde exhausted its capacity in 2003. A Dry Cask Storage Facility (the Facility), also called the Independent Spent Fuel Storage Installation (ISFSI), was built and completed in 2003 at a total cost of $33.9 million (about $2 million for the Authority). In addition to the Facility, the costs also include heavy lift equipment inside the units and at the yard, railroad track, tractors, transporter, transport canister, and surveillance equipment. The Facility has the capacity to store all the spent fuel generated by the Palo Verde plant until 2027. To date, over 117 casks, each containing 24 spent fuel assemblies were placed in the Facility. The original plan called for the annual transfer of about 240 fuel assemblies from the wet pool to the Facility. In the aftermath of the nuclear incident at Fukushima Daiichi Nuclear Station in Japan, following the strong earthquake and subsequent tsunami in 2011, Palo Verde decided to accelerate its campaign to transfer spent fuel from the spent fuel pool to the Facility to relieve the congestion within the pool. The plan in the future is the purchase of new large-capacity casks that were designed to hold 36 assemblies per cask and help to extend the storage capacity of the current Facility possibly until 2047. Storing spent fuel at Palo Verde is now considered indefinite with undetermined costs until spent fuel is removed from the plant site.

The Senate Energy and Natural Resources Committee is currently considering bipartisan legislation to address both interim and long-term spent fuel storage. The bill sponsors include California's Senator Dianne Feinstein.

As of June 30, 2015, 129 dry casks, each containing 24 spent fuel assemblies, have been stored. In addition, beginning in 2016, PVNGS is expected to use the newly designed "magnastor" casks that contain 36 spent fuel assemblies allowing the dry cask storage facility to accept more spent fuel.

Nuclear insurance – The Price-Anderson Act (the Act) requires that all utilities with nuclear generating facilities share in the payment for liability claims resulting from a nuclear incident. The Act limits liability from third-party claims to approximately $13.4 billion per incident. Participants in the Palo Verde Nuclear Generating Station (PVNGS) currently insure potential claims and liability through commercial insurance with a $375 million limit; the remainder of the potential liability is covered by the industry-wide retrospective assessment program provided under the Act. This program limits assessments to $127.3 million per operating reactor for each licensee (there are about 100 operating reactors in the U.S.) for each nuclear incident occurring at any nuclear reactor in the United States; payments under the program are limited to $26.2 million per reactor, per incident, per year to be indexed for inflation every five years. Based on the Authority's 5.91% interest in Palo Verde, the Authority would be responsible for a maximum assessment of $22.6 million per incident for all three units, limited to payments of $4.5 million per incident, per year.

In addition to the above, the Authority may be subject to retroactive insurance assessments for its participation in the Neil Property Insurance Program in the amount of $2.5 million.

Note 11 – Commitments and Contingencies (continued)

Other commitments – The NRC guidelines require improved security in immediate areas surrounding the reactor buildings. PVNGS has enlarged the protected area with the inclusion of an outage support facility, a new warehouse, a minor vehicle maintenance facility, and a fuel depot to reduce vehicular traffic in and out of the protected area. While some of these facilities have already been constructed and are currently in service, the estimated cost for the remaining facilities is approximately $1.1 million to the Authority.

Other major capital projects that are currently in progress include the cyber security upgrade, digital upgrade of the Generrex generator excitation system, the life extension of the Water Reclamation Facility's clarifiers, the spray pond concrete replacement, the Nuclear Administrative and Technical Manual replacement, and the construction of the Learning Center-In Processing facility. These, along with other regulatory plant modifications, are currently estimated at $235 million which translates to approximately $13.6 million for the Authority. Also anticipated in the long-range plan are $224 million ($16 million for the Authority) worth of capital projects which include the cooling tower life extension long-range plan, upgrades to the high-pressure turbines and electro-hydraulic controls, the replacement of the reactor coolant pumps, Control Element Drive Mechanism Control System (CEDMCS), plant cooling water pipelines, and the Site Work Management System (SWMS).

In response to the nuclear event in Fukushima, Japan, the NRC has required PVNGS to implement the following: increase the redundancy in its power supply to emergency cooling systems, reinforce its spent fuel pool, accelerate the transfer of spent fuel from the pool to the dry cask storage, add pipelines and associated equipment necessary for supplying additional cooling water to the reactors, and upgrade the communication and control system to allow remote access to the plant. To date, the station has purchased additional diesel generators, pumps, hoses, fire trucks and stages at the plant site. It also has access to other emergency equipment stored by the nuclear industry in two facilities in Memphis, Tennessee and Phoenix, Arizona. In addition to these, Palo Verde has allotted approximately $122 million (approximately $7.2 million for the Authority) for Fukushima initiatives which include fuel building modifications, an emergency equipment storage facility, temporary power connections, seismic and flood hazards validation, and corresponding mitigating strategies, among several others. All Fukushima upgrade-related activities are expected to be implemented by the end of 2016. Additional NRC-mandated requirements are anticipated but the costs associated with these future projects are unknown at this time.

Note 11 – Commitments and Contingencies (continued)

Other legal matters – Claims and a lawsuit for damages have been filed with the Authority, Intermountain Power Authority (the IPA), and LADWP seeking in excess of $500 million in damages. The claimants allege, among other things, that due to improper grounding of the transmission line of STS, their dairy herds were damaged and the value of their land was diminished. The Authority believed these claims were substantially without merit as to itself because the Authority has no ownership or operational control over the subject transmission lines, and merely acted as a financing agency with respect to STS. Phase 1 of the trial, limited to the owners of six dairies, began on September 30, 2013, but after 20 trial days ended in a mistrial. Plaintiffs appealed that ruling to the Utah Court of Appeals, which heard oral argument on May 20, 2015, but has not yet issued a ruling. A new trial date has not yet been set even though the trial occurred nearly two years ago. No determination can be made at this time whether an unfavorable outcome is probable or remote, nor can an accurate estimate be made of the range of potential loss.

The Authority is also involved in various other legal actions. In the opinion of management, the outcome of such litigation or claims will not have a material effect on the financial position or the results of operations of the Authority or the respective separate Projects.

Note 12 – Subsequent Events

Don A. Campbell 2 Geothermal Energy Project – On December 18, 2014 the Authority entered into a power purchase agreement with ORNI 37 LLC to purchase renewable geothermal energy from the Don A. Campbell 2 Facility (DAC2) beginning December 31, 2016, for a 20-year term. The Facility is a geothermal power generating facility with a 16.2 MW nameplate capacity and a 95% capacity factor located in Mineral County, Nevada. The commercial operating date was September 17, 2015, but early delivery of energy began in August 2015. The LADWP acts as project manager and has balancing authority at the point of delivery of energy at the Mead 230kV Substation in Southern Nevada. Electricity from the Project will be transmitted through Nevada Energy's Transmission System that includes the new 500 kV One Nevada Transmission Line. Consequently, the Don A. Campbell/Wild Rose Facility is now called Don A. Campbell 1 to distinguish from the expansion, DAC2.

REQUIRED SUPPLEMENTARY INFORMATION

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
SCHEDULE OF PROPORTIONATE SHARE OF THE NET PENSION LIABILITY
AS OF JUNE 30, 2015
LAST TEN YEARS*

	2015
Proportion of the net pension liability	0.01404%
Proportionate share of the net pension liability	$ 873,857
Covered - employee payroll	$ 1,091,557
Proportionate Share of the net pension liability as percentage of covered-employee payroll	80.06%
Plan's fiduciary net position	$ 24,940,528
Plan fiduciary net position as a percentage of the total pension liability	81.00%

Notes to Schedule

Benefit changes – In 2015, benefit terms were modified to base public safety employee pensions on a final three-year average salary instead of a final five-year average salary.

Changes in assumptions – In 2015, amounts reported as changes in assumptions resulted primarily from adjustments to expected retirement ages of general employees.

*Fiscal year 2015 was the 1st year of implementation, therefore only one year is shown.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
SCHEDULE OF CONTRIBUTIONS
AS OF JUNE 30, 2015
LAST TEN YEARS*

	2015
Contractually required contribution (actuarially determined)	$ 699,279
Contributions in relation to the actuarially determined contribution	(699,279)
Contribution deficiency (excess)	$ -
Covered-employee payroll	$ 1,091,557
Contributions as a percentage of covered-employee payroll	64.06%

Notes to Schedule

Valuation date: 6/30/2013

Methods and assumptions used to determine contribution rates:

Single and Agent Employers Example	Entry age
Amortization method	Level percentage of payroll, closed
Remaining amortization period	15 years
Asset valuation method	5-year smoothed market
Inflation	3.50%
Salary increases	4.5%, average, including inflation of 3.0%
Investment rate of return	7.5%, net of pension plan investment expense, including inflation
Retirement age	57 yrs.
Mortality	RP-2000 Healthy Annuitant Mortality Table

*Fiscal year 2015 was the 1st year of implementation, therefore only one year is shown.

SUPPLEMENTAL INFORMATION

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
PALO VERDE PROJECT
SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS IN FUNDS REQUIRED BY THE BOND INDENTURE FOR THE YEAR ENDED JUNE 30, 2015
(AMOUNTS IN THOUSANDS)

	Debt Service Fund	Decommissioning Trust Fund	Escrow Account	General Reserve Account	Issue Account	Operating Account	Reserve & Contingency	Revenue Fund	Total
Balance at June 30, 2014	$ -	$ 170,198	$ 162,646	$ 1,305	$ 13,117	$ 41,999	$ 17,566	$ -	$ 406,831
Additions									
Investment earnings	-	2,204	27,244	13	4	997	173	-	30,635
Discount on investment purchases	-	-	-	-	3	1	1	-	5
Distribution of investment earnings	-	-	-	(13)	(7)	(100)	(173)	293	-
Revenue from power sales	-	-	-	-	-	-	-	81,113	81,113
Distribution of revenue	-	-	-	-	11,725	55,977	13,704	(81,406)	-
Other receipts	-	-	-	-	-	5,880	-	-	5,880
Transfer from escrow	27,736	-	(45,119)	-	17,383	-	-	-	-
Total additions	27,736	2,204	(17,875)	-	29,108	62,755	13,705	-	117,633
Deductions									
Construction expenditures	-	-	-	-	-	14	14,656	-	14,670
Operating expenditures	-	3	-	-	-	44,522	(14)	-	44,511
Fuel costs	-	-	-	-	-	16,478	-	-	16,478
Payment of principal	-	-	-	-	11,330	-	-	-	11,330
Interest paid - non-escrow	-	-	-	-	203	-	-	-	203
Payment of principal and interest – escrow	27,736	-	-	-	17,383	-	-	-	45,119
Total deductions	27,736	3	-	-	28,916	61,014	14,642	-	132,311
Balance at June 30, 2015	$ -	$ 172,399	$ 144,771	$ 1,305	$ 13,309	$ 43,740	$ 16,629	$ -	$ 392,153

This schedule summarizes the receipts and disbursements in funds required under the Bond Indenture and has been prepared from the trust statements. The balances in the funds consist of cash and investments at original cost. These balances do not include accrued interest receivable, unrealized gain (loss) on investments, or $24 and $34 held in the revolving fund at June 30, 2015 and 2014, respectively.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
SAN JUAN PROJECT
SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS IN FUNDS REQUIRED BY THE BOND INDENTURE FOR THE YEAR ENDED JUNE 30, 2015
(AMOUNTS IN THOUSANDS)

	Debt Service Fund	Debt Service Reserve Account	Revenue Fund	Operating Fund	Reserve & Contingency Fund	Cost of Issuance	Escrow Account	Mine Reclamation Fund	Total
Balance at June 30, 2014	$ 7,297	$ 7,799	$ -	$ 13,713	$ 12,295	$ -	$ -	$ 2,442	$ 43,546
Additions									
Investment earnings	6	165	1	8	52	-	-	20	252
Discount on investments	3	-	-	8	2	-	-	1	14
Distribution of investment earnings	(9)	(1)	80	(16)	(54)	-	-	-	-
Revenue from power sales	-	-	87,760	-	-	-	-	-	87,760
Distribution of revenues	28,502	-	(87,841)	58,139	1,200	-	-	-	-
Bond proceeds 2014A	-	-	-	-	-	313	42,622	-	42,935
Transfer funds for debt service payment	(23,247)	(7,963)	-	-	-	-	31,210	-	-
Other	14,997	25	-	(420)	-	(25)	(14,997)	420	-
Total additions	20,252	(7,774)	-	57,719	1,200	288	58,835	441	130,961
Deductions									
Operating expenses	-	-	-	65,535	-	288	-	-	65,823
Construction expenses	-	-	-	-	114	-	-	-	114
Payment of principal - escrow	13,200	-	-	-	-	-	58,680	-	71,880
Interest paid – non-escrow	1,797	-	-	-	-	-	-	-	1,797
Interest paid – escrow	1,797	-	-	-	-	-	155	-	1,952
Interest on investment purchases	(9)	-	-	3	1	-	-	-	(5)
Total deductions	16,785	-	-	65,538	115	288	58,835	-	141,561
Balance at June 30, 2015	$ 10,764	$ 25	$ -	$ 5,894	$ 13,380	$ -	$ -	$ 2,883	$ 32,946

This schedule summarizes the receipts and disbursements in funds required under the Bond Indenture and has been prepared from the trust statements. The balances in the funds consist of cash and investments at original cost. These balances do not include accrued interest receivable, unrealized gain (loss) on investments or $18 and $19 held in the revolving fund at June 30, 2015 and 2014, respectively.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
MAGNOLIA POWER PROJECT
SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS IN FUNDS REQUIRED BY THE BOND INDENTURE FOR THE YEAR ENDED JUNE 30, 2015
(AMOUNTS IN THOUSANDS)

	Debt Service Account	Debt Service Reserve Account	Project Fund	Operating Reserve Fund	Reserve & Contingency	Operating Fund	Revenue Fund	General Reserve Fund	Escrow Fund	Fuel Reserve Fund	GHG Reserve Fund	Total
Balance at June 30, 2014	$ 14,758	$ 28,824	$ 28	$ 4,926	$ 25,341	$ 6,098	$ -	$ 9,602	$ -	$ -	$ -	$ 89,577
Additions												
Investment earnings	4	466	-	50	194	8	1	14	-	9	-	746
Discount on investment purchases	4	1	-	-	2	-	-	-	-	-	-	7
Distribution of investment earnings	(8)	(467)	-	(49)	(196)	(7)	727	-	-	-	-	-
Transfer of funds for debt service payment	-	-	-	-	-	-	-	-	-	-	-	-
Receipt from participants	-	-	-	-	-	-	49,127	-	-	-	-	49,127
Distribution of revenues	22,809	-	(28)	-	(1,798)	20,984	(49,855)	4,653	-	3,235	-	-
Other	-	-	-	-	-	7,215	-	(14,179)	-	4,067	2,897	-
Total additions	22,809	-	(28)	1	(1,798)	28,200	-	(9,512)	-	7,311	2,897	49,880
Deductions												
Construction expenses	-	-	-	-	1,331	-	-	-	-	-	-	1,331
Operating expenses	-	-	-	-	131	26,396	-	-	-	-	-	26,527
Payment of principal	10,565	-	-	-	-	-	-	-	-	-	-	10,565
Interest paid	11,368	-	-	-	-	-	-	-	-	-	-	11,368
Premium and interest on investment purchases	-	-	-	-	-	-	-	-	-	1	-	1
Payment of principal and interest - escrow	-	-	-	-	-	-	-	-	-	-	-	-
Total deductions	21,933	-	-	-	1,462	26,396	-	-	-	1	-	49,792
Balance at June 30, 2015	$ 15,634	$ 28,824	$ -	$ 4,927	$ 22,081	$ 7,902	$ -	$ 90	$ -	$ 7,310	$ 2,897	$ 89,665

This schedule summarizes the receipts and disbursements in funds required under the Bond Indenture and has been prepared from the trust statements. The balances in the funds consist of cash and investments at original cost. These balances do not include accrued interest receivable, unrealized gain (loss) on investments, or $27 and $28 held in the revolving fund at June 30, 2015 and 2014, respectively.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
CANYON POWER PROJECT
SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS IN FUNDS REQUIRED BY THE BOND INDENTURE FOR THE YEAR ENDED JUNE 30, 2015
(AMOUNTS IN THOUSANDS)

	Revenue Fund	Operating Fund	Debt Service Fund	Debt Service Reserve Fund	Project Fund	U.S. Treasury Direct Subsidy	Total
Balance at June 30, 2014	$ -	$ 1,677	$ 7,157	$ 19,721	$ 4,360	$ -	$ 32,915
Additions							
Investment earnings	-	2	1	275	4	-	282
Discount on investment purchases	-	-	4	-	2	-	6
Distribution of investment earnings	282	(2)	(5)	(275)	-	-	-
Receipt from participants	15,323	-	-	-	-	-	15,323
Distribution of revenues	(15,605)	1,340	17,940	-	-	(3,675)	-
Other	-	-	-	-	-	5,511	5,511
Total additions	-	1,340	17,940	-	6	1,836	21,122
Deductions							
Construction expenses	-	-	-	-	128	-	128
Operating expenses	-	2,386	-	-	-	-	2,386
Interest paid	-	-	16,731	-	-	-	16,731
Total deductions	-	2,386	16,731	-	128	-	19,245
Balance at June 30, 2015	$ -	$ 631	$ 8,366	$ 19,721	$ 4,238	$ 1,836	$ 34,792

This schedule summarizes the receipts and disbursements in funds required under the Bond Indenture and has been prepared from the trust statements. The balances in the funds consist of cash and investments at original cost. These balances do not include accrued interest receivable or unrealized gain (loss) on investments, or $18 and $19 held in the revolving fund at June 30, 2015 and 2014, respectively.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
APEX POWER PROJECT
SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS IN FUNDS REQUIRED BY THE BOND INDENTURE FOR THE YEAR ENDED JUNE 30, 2015
(AMOUNTS IN THOUSANDS)

	Revenue Fund	Depository Fund	Operating Fund	Debt Service Fund	Debt Service Reserve Fund	Reserve & Contingency Fund	General Reserve	Project Fund	Cost of Issuance Fund	Total
Balance at June 30, 2014	$ -	$ -	$ 17,430	$ 3,327	$ 5,488	$ 1,001	$ -	$ 29,916	$ 58	$ 57,220
Additions										
Investment earnings	-	-	6	4	97	11	-	39	-	157
Discount on investment purchases	4	-	(2)	(2)	-	-	-	16	-	16
Distribution of investment earnings	114	-	(4)	(2)	(97)	(11)	-	-	-	-
Receipt from participants	53,914	-	-	-	-	-	-	-	-	53,914
Distribution of revenues	(54,032)	7,181	21,911	21,944	-	2,996	-	-	-	-
Other Transfers	-	-	536	-	-	-	58	(536)	(58)	-
Other	-	-	2,925	-	-	-	-	-	-	2,925
Total additions	-	7,181	25,372	21,944	-	2,996	58	(481)	(58)	57,012
Deductions										
Acquisition costs	-	-	-	-	-	-	-	-	-	-
Operating expenses	-	7,181	25,362	-	-	-	-	-	-	32,543
Debt issuance costs	-	-	-	9,632	-	-	-	-	-	9,632
Total deductions	-	7,181	25,362	9,632	-	-	-	-	-	42,175
Balance at June 30, 2015	$ -	$ -	$ 17,440	$ 15,639	$ 5,488	$ 3,997	$ 58	$ 29,435	$ -	$ 72,057

This schedule summarizes the receipts and disbursements in funds required under the Bond Indenture and has been prepared from the trust statements. The balances in the funds consist of cash and investments at original cost. These balances do not include accrued interest receivable and unrealized gain (loss) on investments, or $21 held in the revolving fund at June 30, 2015. No balance was held in the revolving fund at June 30, 2014.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
HOOVER UPRATING PROJECT
SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS IN FUNDS REQUIRED BY THE BOND INDENTURE FOR THE YEAR ENDED JUNE 30, 2015
(AMOUNTS IN THOUSANDS)

	Debt Service Fund	General Reserve Fund	Operating Fund	Revenue Fund	Total
Balance at June 30, 2014	$ 1,480	$ 1,700	$ 1,332	$ -	$ 4,512
Additions					
Investment earnings	-	24	-	-	24
Distribution of investment earnings	-	(24)	9	15	-
Revenue from power sales	-	-	-	2,539	2,539
Distribution of revenue	2,250	-	304	(2,554)	-
Total additions	2,250	-	313	-	2,563
Deductions					
Operating expenses	-	-	308	-	308
Payment of principal	1,835	-	-	-	1,835
Interest paid	368	-	-	-	368
Total deductions	2,203	-	308	-	2,511
Balance at June 30, 2015	$ 1,527	$ 1,700	$ 1,337	$ -	$ 4,564

This schedule summarizes the receipts and disbursements in funds required under the Bond Indenture and has been prepared from the trust statements. The balances in the funds consist of cash and investments at original cost. These balances do not include accrued interest receivable, unrealized gain (loss) on investments, or $15 held in the revolving fund at June 30, 2015 and 2014.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
TIETON HYDROPOWER PROJECT
SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS IN FUNDS REQUIRED BY THE BOND INDENTURE FOR THE YEAR ENDED JUNE 30, 2015
(AMOUNTS IN THOUSANDS)

	Revenue Fund	Operating Fund	Debt Service Fund	Debt Service Reserve Fund	Reserve & Contingency Fund	General Reserve Fund	Total
Balance at June 30, 2014	$ -	$ 675	$ 2,088	$ 5,008	$ 500	$ 24	$ 8,295
Additions							
Investment earnings	-	1	1	65	2	-	69
Distribution of investment earnings	69	(1)	(1)	(65)	(2)	-	-
Receipt from participants	4,885	-	-	-	-	-	4,885
Distribution of revenues	(4,954)	1,596	3,358	-	-	-	-
Other transfers	-	81	-	-	(81)	-	-
Other receipts	-	-	-	-	-	-	-
Total additions	-	1,677	3,358	-	(81)	-	4,954
Deductions							
Acquisition costs	-	-	-	-	-	-	-
Operating expenses	-	1,782	-	-	-	-	1,782
Payment of principal	-	-	815	-	-	-	815
Interest paid	-	-	2,532	-	-	-	2,532
Total deductions	-	1,782	3,347	-	-	-	5,129
Balance at June 30, 2015	$ -	$ 570	$ 2,099	$ 5,008	$ 419	$ 24	$ 8,120

This schedule summarizes the receipts and disbursements in funds required under the Bond Indenture and has been prepared from the trust statements. The balances in the funds consist of cash and investments at original cost. These balances do not include accrued interest receivable, unrealized gain (loss) on investments, or $9 held in the revolving fund at June 30, 2015 and 2014.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
MILFORD 1 WIND PROJECT
SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS IN FUNDS REQUIRED BY THE BOND INDENTURE FOR THE YEAR ENDED JUNE 30, 2015
(AMOUNTS IN THOUSANDS)

	Revenue Fund	Operating Fund	Debt Service Fund	Debt Service Reserve Fund	General Reserve Fund	Operating Reserve Fund	Total
Balance at June 30, 2014	$ -	$ 8,714	$ 13,662	$ 18,874	$ 2,520	$ 3,000	$ 46,770
Additions							
Investment earnings	-	5	3	239	35	32	314
Discount on investments	-	5	9	-	-	-	14
Distribution of investment earnings	328	(10)	(12)	(239)	(35)	(32)	-
Receipt from participants	26,928	-	-	-	-	-	26,928
Distribution of revenues	(27,256)	8,386	18,870	-	-	-	-
Other	-	-	-	-	-	-	-
Total additions	-	8,386	18,870	-	-	-	27,256
Deductions							
Operating expenses	-	12,662	-	-	-	-	12,662
Payment of principal	-	-	8,450	-	-	-	8,450
Interest paid	-	-	10,236	-	-	-	10,236
Total deductions	-	12,662	18,686	-	-	-	31,348
Balance at June 30, 2015	$ -	$ 4,438	$ 13,846	$ 18,874	$ 2,520	$ 3,000	$ 42,678

This schedule summarizes the receipts and disbursements in funds required under the Bond Indenture and has been prepared from the trust statements. The balances in the funds consist of cash and investments at original cost. These balances do not include accrued interest receivable, unrealized gain (loss) on investments, or $9 held in the revolving fund at June 30, 2015 and 2014.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
MILFORD 2 WIND PROJECT
SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS IN FUNDS REQUIRED BY THE BOND INDENTURE FOR THE YEAR ENDED JUNE 30, 2015
(AMOUNTS IN THOUSANDS)

	Revenue Fund	Operating Fund	Debt Service Fund	Debt Service Reserve Fund	Total
Balance at June 30, 2014	$ -	$ 5,922	$ 9,067	$ 3,216	$ 18,205
Additions					
Investment earnings	-	6	2	43	51
Discount on investments	-	-	5	-	5
Distribution of investment earnings	56	(6)	(7)	(43)	-
Receipt from participants	17,690	-	-	-	17,690
Distribution of revenues	(17,746)	4,885	12,861	-	-
Total additions	-	4,885	12,861	-	17,746
Deductions					
Operating expenses	-	5,589	-	-	5,589
Payment of principal	-	-	5,270	-	5,270
Interest paid	-	-	7,463	-	7,463
Total deductions	-	5,589	12,733	-	18,322
Balance at June 30, 2015	$ -	$ 5,218	$ 9,195	$ 3,216	$ 17,629

This schedule summarizes the receipts and disbursements in funds required under the Bond Indenture and has been prepared from the trust statements. The balances in the funds consist of cash and investments at original cost. These balances do not include accrued interest receivable, unrealized gain (loss) on investments, or $9 held in the revolving fund at June 30, 2015 and 2014.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
WINDY POINT PROJECT
SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS IN FUNDS REQUIRED BY THE BOND INDENTURE FOR THE YEAR ENDED JUNE 30, 2015
(AMOUNTS IN THOUSANDS)

	Revenue Fund	Operating Fund	Debt Service Fund	Debt Service Reserve Fund	Total
Balance at June 30, 2014	$ -	$ 7,565	$ 29,789	$ 10,262	$ 47,616
Additions					
Investment earnings	-	11	4	176	191
Discount on investments	-	2	21	-	23
Distribution of investment earnings	213	(13)	(25)	(176)	(1)
Receipt from participants	76,460	35,628	41,045	-	153,133
Distribution of revenue	(76,673)	-	-	-	(76,673)
Total additions	-	35,628	41,045	-	76,673
Deductions					
Operating expenses	-	34,222	-	-	34,222
Payment of principal	-	-	18,535	-	18,535
Interest paid	-	-	22,081	-	22,081
Total deductions	-	34,222	40,616	-	74,838
Balance at June 30, 2015	$ -	$ 8,971	$ 30,218	$ 10,262	$ 49,451

This schedule summarizes the receipts and disbursements in funds required under the Bond Indenture and has been prepared from the trust statements. The balances in the funds consist of cash and investments at original cost. These balances do not include accrued interest receivable, unrealized gain (loss) on investments, or $9 held in the revolving fund at June 30, 2015 and 2014.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
LINDEN WIND ENERGY PROJECT
SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS IN FUNDS REQUIRED BY THE BOND INDENTURE FOR THE YEAR ENDED JUNE 30, 2015
(AMOUNTS IN THOUSANDS)

	Revenue Fund	Operating Fund	Debt Service Fund	Debt Service Reserve Fund	General Reserve Fund	Project Fund	U.S. Treasury Direct Subsidy	Total
Balance at June 30, 2014	$ -	$ 2,589	$ 6,444	$ 2,324	$ 69	$ 585	$ -	$ 12,011
Additions								
Investment earnings	-	2	1	23	-	2	-	28
Discount on investments	-	1	4	-	-	-	-	5
Distribution of investment earnings	31	(3)	(5)	(23)	-	-	-	-
Revenue from power sales	16,697	-	-	-	-	-	-	16,697
Distribution of revenue	(16,728)	6,573	10,155	-	-	-	-	-
Other transfers	-	400	399	-	-	-	(799)	-
Other receipts	-	-	-	-	-	-	1,198	1,198
Total additions	-	6,973	10,554	-	-	2	399	17,928
Deductions								
Operating expenses	-	7,830	-	-	-	-	-	7,830
Payment of principal	-	-	3,530	-	-	-	-	3,530
Interest paid	-	-	6,555	-	-	-	-	6,555
Total deductions	-	7,830	10,085	-	-	-	-	17,915
Balance at June 30, 2015	$ -	$ 1,732	$ 6,913	$ 2,324	$ 69	$ 587	$ 399	$ 12,024

This schedule summarizes the receipts and disbursements in funds required under the Bond Indenture and has been prepared from the trust statements. The balances in the funds consist of cash and investments at original cost. These balances do not include accrued interest receivable, unrealized gain (loss) on investments, or $9 and $12 held in the revolving fund at June 30, 2015 and 2014, respectively.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
SOUTHERN TRANSMISSION SYSTEM PROJECT
SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS IN FUNDS REQUIRED BY THE BOND INDENTURE FOR THE YEAR ENDED JUNE 30, 2015
(AMOUNTS IN THOUSANDS)

	General Reserve Fund	Issue Fund	Upgrade Construction Fund	Operating Fund	Revenue Fund	Escrow Fund	Total
Balance at June 30, 2014	$ 3,099	$ 86,278	$ 8,204	$ 121	$ -	$ -	$ 97,702
Additions							
Investment earnings	2	694	2	3	1	-	702
Discount on investment purchases	2	45	13	1	-	-	61
Distribution of investment earnings	(4)	(739)	-	(4)	747	-	-
Revenue from transmission sales	-	-	-	-	106,683	-	106,683
Distribution of revenue	(200)	78,964	-	28,748	(107,512)	-	-
Bond Proceeds 2015A&B	-	28,925	-	-	-	101,999	130,924
Bond Proceeds 2015C	-	597	-	-	-	141,639	142,236
Transfer (from) / to escrow fund for principal and interest payment	-	(1)	(4,491)	-	-	4,492	-
Other	-	3,647	(3,728)	-	81	-	-
Total additions	(200)	112,132	(8,204)	28,748	-	248,130	380,606
Deductions							
Construction expenses	-	-	-	-	-	-	-
Operating expenses	-	-	-	23,911	-	-	23,911
Payment of principal	-	50,885	-	-	-	-	50,885
Interest paid	-	31,347	-	-	-	-	31,347
Debt issuance costs	-	1,237	-	-	-	-	1,237
Premium and interest on investment purchases		1	-	-	-	-	1
2000A Principal Payment Redemption - Escrow		29,660	-	-	-	102,000	131,660
2008B Bond Redemption - Escrow		-	-	-	-	146,130	146,130
Total deductions	-	113,130	-	23,911	-	248,130	385,171
Balance at June 30, 2015	$ 2,899	$ 85,280	$ -	$ 4,958	$ -	$ -	$ 93,137

This schedule summarizes the receipts and disbursements in funds required under the Bond Indenture and has been prepared from the trust statements. The balances in the funds consist of cash and investments at original cost. These balances do not include accrued interest receivable, unrealized gain (loss) on investments, or $21 and $25 held in the revolving fund at June 30, 2015 and 2014, respectively.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
MEAD-PHOENIX PROJECT
SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS IN FUNDS REQUIRED BY THE BOND INDENTURE FOR THE YEAR ENDED JUNE 30, 2015
(AMOUNTS IN THOUSANDS)

	Revenue Fund	Debt Service Account	Debt Service Reserve Account	Operating Fund	Reserve & Contingency Fund	Cost of Issuance Fund	Total
Balance at June 30, 2014	$ -	$ 6,027	$ -	$ 307	$ -	$ 371	$ 6,705
Additions							
Investment earnings	-	1	-	1	-	-	2
Discount on investment earnings	-	2	-	-	-	-	2
Distribution of investment earnings	4	(3)	-	(1)	-	-	-
Transmission revenue	10,408	-	-	-	-	-	10,408
Distribution of revenues	(10,412)	6,865	-	3,407	140	-	-
Other	-	-	-	2	-	-	2
Total additions	-	6,865	-	3,409	140	-	10,414
Deductions							
Operating expenses	-	-	-	2,709	-	-	2,709
Construction expenses	-	-	-	-	128	-	128
Principal payment	-	5,215	-	-	-	-	5,215
Interest and SWAP paid	-	1,507	-	-	-	-	1,507
Total deductions	-	6,722	-	2,709	128	-	9,559
Balance at June 30, 2015	$ -	$ 6,170	$ -	$ 1,007	$ 12	$ 371	$ 7,560

This schedule summarizes the receipts and disbursements in funds required under the Bond Indenture and has been prepared from the trust statements. The balances in the funds consist of cash and investments at original cost. These balances do not include accrued interest receivable, unrealized gain (loss) on investments, or $12 and $15 held in the revolving fund at June 30, 2015 and 2014, respectively.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
MEAD-ADELANTO PROJECT
SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS IN FUNDS REQUIRED BY THE BOND INDENTURE FOR THE YEAR ENDED JUNE 30, 2015
(AMOUNTS IN THOUSANDS)

	Revenue Fund	Debt Service Account	Debt Service Reserve Fund	Operating Fund	Reserve & Contingency	Escrow Fund	Surplus Fund	Total
Balance at June 30, 2014	$ -	$ 20,340	$ -	$ 342	$ 42	$ -	$ 7,556	$ 28,280
Additions								
Investment earnings	-	3	-	1	-	-	-	4
Discount on investment earnings	-	13	-	1	-	-	-	14
Distribution of investment earnings	28	(16)	-	(1)	-	-	-	11
Transmission revenue	24,953	-	-	-	-	-	-	24,953
Distribution of revenues	(24,981)	22,763	-	2,218	-	-	-	-
Other	-	-	-	2	-	-	-	2
Total additions	-	22,763	-	2,221	-	-	-	24,984
Deductions								
Principal payment	-	17,385	-	-	-	-	-	17,385
Interest & SWAP paid	-	5,491	-	-	-	-	-	5,491
Operating expenses	-	-	-	1,813	-	-	-	1,813
Total deductions	-	22,876	-	1,813	-	-	-	24,689
Balance at June 30, 2015	$ -	$ 20,227	$ -	$ 750	$ 42	$ -	$ 7,556	$ 28,575

This schedule summarizes the receipts and disbursements in funds required under the Bond Indenture and has been prepared from the trust statements. The balances in the funds consist of cash and investments at original cost. These balances do not include accrued interest receivable, unrealized gain (loss) on investments, or $12 and $15 held in the revolving fund at June 30, 2015 and 2014, respectively.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
NATURAL GAS PINEDALE PROJECT
SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS IN FUNDS REQUIRED BY THE BOND INDENTURE FOR THE YEAR ENDED JUNE 30, 2015
(AMOUNTS IN THOUSANDS)

	Revenue Fund	Operating Fund	Debt Service Fund	General Reserve Fund	Project Fund	Capital Fund	Total
Balance at June 30, 2014	$ -	$ 7,803	$ 2,968	$ 38	$ 2,701	$ 5,743	$ 19,253
Additions							
Investment earnings	-	5	1	-	2	4	12
Discount on investment purchases	-	-	-	-	-	3	3
Distribution of investment earnings	1	-	(1)	-	-	-	-
Receipt from participants	4,283	4,216	-	-	-	-	8,499
Sales of natural gas	889	8,967	-	-	-	-	9,856
Distribution of revenues	(5,173)	7,388	3,661	-	(7)	(5,869)	-
Other transfer	-	-	-	-	(1)	1	-
Total additions	-	20,576	3,661	-	(6)	(5,861)	18,370
Deductions							
Construction expenses	-	-	-	-	-	129	129
Operating expenses	-	24,563	-	-	-	-	24,563
Payment of principal	-	-	2,219	-	-	-	2,219
Interest paid	-	-	1,439	-	-	-	1,439
Total deductions	-	24,563	3,658	-	-	129	28,350
Balance at June 30, 2015	$ -	$ 3,816	$ 2,971	$ 38	$ 2,695	$ (247)	$ 9,273

This schedule summarizes the receipts and disbursements in funds required under the Bond Indenture and has been prepared from the trust statements. The balances in the funds consist of cash and investments at original cost. These balances do not include accrued interest receivable, unrealized gain (loss) on investments, or $30 and $37 held in the revolving fund at June 30, 2015 and 2014, respectively.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
NATURAL GAS BARNETT PROJECT
SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS IN FUNDS REQUIRED BY THE BOND INDENTURE FOR THE YEAR ENDED JUNE 30, 2015
(AMOUNTS IN THOUSANDS)

	Revenue Fund	Operating Fund	Debt Service Fund	General Reserve Fund	Project Fund	Capital Fund	Total
Balance at June 30, 2014	$ -	$ 3,194	$ 6,964	$ 22	$ 39,679	$ (5,679)	$ 44,180
Additions							
Investment earnings	-	3	3	-	219	1	226
Discount on investment purchases	-	-	1	-	2	-	3
Distribution of investment earnings	4	-	(4)	-	-	-	-
Receipt from participants	9,781	174	-	-	-	-	9,955
Sales of natural gas	3,690	820	-	-	-	-	4,510
Distribution of revenues	(13,530)	3,979	8,589	-	(116)	1,078	-
Other receipts	55	(55)	-	-	55	12	67
Total additions	-	4,921	8,589	-	160	1,091	14,761
Deductions							
Construction expenses	-	-	-	-	-	703	703
Operating expenses	-	6,093	-	-	-	-	6,093
Payment of principal	-	-	5,211	-	-	-	5,211
Interest paid	-	-	3,384	-	-	-	3,384
Total deductions	-	6,093	8,595	-	-	703	15,391
Balance at June 30, 2015	$ -	$ 2,022	$ 6,958	$ 22	$ 39,839	$ (5,291)	$ 43,550

This schedule summarizes the receipts and disbursements in funds required under the Bond Indenture and has been prepared from the trust statements. The balances in the funds consist of cash and investments at original cost. These balances do not include accrued interest receivable, unrealized gain (loss) on investments, or $18 and $19 held in the revolving fund at June 30, 2015 and 2014, respectively.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
PREPAID NATURAL GAS PROJECT No. 1
SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS IN FUNDS REQUIRED BY THE BOND INDENTURE FOR THE YEAR ENDED JUNE 30, 2015
(AMOUNTS IN THOUSANDS)

	Revenue Fund	Operating Fund	Debt Service Fund	Total
Balance at June 30, 2014	$ -	$ 15,162	$ 3,261	$ 18,423
Additions				
Investment earnings	-	487	202	689
Distribution of investment earnings	483	(2,619)	-	(2,136)
Receipt from gas sales	7,429	-	-	7,429
Distribution of revenues	(17,625)	-	19,761	2,136
Commodity swap settlement	9,713	-	-	9,713
Other receipts	-	-	587	587
Total additions	-	(2,132)	20,550	18,418
Deductions				
A & G expenses	-	476	-	476
Payment of principal	-	-	3,875	3,875
Payment of interest	-	-	16,444	16,444
Total deductions	-	476	20,319	20,795
Balance at June 30, 2015	$ -	$ 12,554	$ 3,492	$ 16,046

This schedule summarizes the receipts and disbursements in funds required under the Bond Indenture and has been prepared from the trust statements. The balances in the funds consist of cash and investments at original cost. These balances do not include accrued interest receivable, unrealized gain (loss) on investments, or $18 and $19 held in the revolving fund at June 30, 2015 and 2014, respectively.

KPMG

LOS ANGELES DEPARTMENT OF WATER AND POWER
POWER SYSTEM

Financial Statements and
Required Supplementary Information

June 30, 2014 and 2013

(With Independent Auditors' Report Thereon)

LOS ANGELES DEPARTMENT OF WATER AND POWER
POWER SYSTEM

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KPMG

KPMG LLP
Suite 1500
550 South Hope Street
Los Angeles, CA 90071-2629

Independent Auditors' Report

The Board of Water and Power Commissioners
Department of Water and Power
City of Los Angeles:

Report on the Financial Statements

We have audited the accompanying financial statements of the City of Los Angeles' Department of Water and Power's Power Revenue Fund (Power System), an enterprise fund of the City of Los Angeles, California, as of and for the years ended June 30, 2014 and 2013, and the related notes to the financial statements, which collectively comprise the Power System's basic financial statements as listed in the table of contents.

Management's Responsibility for the Financial Statements

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

Auditors' Responsibility

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

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

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

KPMG

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Power System as of June 30, 2014 and 2013, and changes in its financial position and its cash flows for the years then ended in accordance with U.S. generally accepted accounting principles.

Emphasis of Matter

As discussed in note 1, the financial statements present only the Power System and do not purport to, and do not, present fairly the financial position of the City of Los Angeles, California, as of June 30, 2014 and 2013, the changes in its financial position, or, where applicable, its cash flows for the year then ended in accordance with accounting principles generally accepted in the United States of America. Our opinion is not modified with respect to this matter.

Other Matters

Required Supplementary Information

U.S. generally accepted accounting principles require that the management's discussion and analysis and the required supplementary information on pages 3–14 and 73, respectively, be presented to supplement the basic financial statements. Such information, although not a part of the basic financial statements, is required by the Governmental Accounting Standards Board who considers it to be an essential part of financial reporting for placing the basic financial statements in an appropriate operational, economic, or historical context. We have applied certain limited procedures to the required supplementary information in accordance with auditing standards generally accepted in the United States of America, which consisted of inquiries of management about the methods of preparing the information and comparing the information for consistency with management's responses to our inquiries, the basic financial statements, and other knowledge we obtained during our audit of the basic financial statements. We do not express an opinion or provide any assurance on the information because the limited procedures do not provide us with sufficient evidence to express an opinion or provide any assurance.

Other Reporting Required by *Government Auditing Standards*

In accordance with *Government Auditing Standards*, we have also issued our report dated December 8, 2014 on our consideration of the Power System's internal control over financial reporting and on our tests of its compliance with certain provisions of laws, regulations, contracts, and grant agreements and other matters. The purpose of that report is to describe the scope of our testing of internal control over financial reporting and compliance and the results of that testing, and not to provide an opinion on internal control over financial reporting or on compliance. That report is an integral part of an audit performed in accordance with *Government Auditing Standards* in considering the Power System's internal control over financial reporting and compliance.

KPMG LLP

Los Angeles, California
December 8, 2014

The following discussion and analysis of the financial performance of the City of Los Angeles' (the City) Department of Water and Power's (the Department) Power Revenue Fund (the Power System) provides an overview of the financial activities for the fiscal years ended June 30, 2014 and 2013. Descriptions and other details pertaining to the Power System are included in the notes to the financial statements. This discussion and analysis should be read in conjunction with the Power System's financial statements, which begin on page 15.

Using this Financial Report

This annual financial report consists of the Power System's financial statements and required supplementary information and reflects the self-supporting activities of the Power System that are funded primarily through the sale of energy, transmission, and distribution services to the public it serves.

Statements of Net Position, Statements of Revenues, Expenses, and Changes in Net Position, and Statements of Cash Flows

The financial statements provide an indication of the Power System's financial health. The statements of net position include all of the Power System's assets, deferred outflows, liabilities, and deferred inflows using the accrual basis of accounting, as well as an indication about which assets can be utilized for general purposes, and which assets are restricted as a result of bond covenants and other commitments. The statements of revenues, expenses, and changes in net position report all of the revenues and expenses during the time periods indicated. The statements of cash flows report the cash provided by and used in operating activities, as well as other cash sources and uses, such as investment income and cash payments for bond principal and capital additions and betterments.

(Continued)

The following table summarizes the financial condition and changes in net position of the Power System as of and for the fiscal years ended June 30, 2014, 2013, and 2012:

Table 1 – Condensed Schedule of Assets, Deferred Outflows, Liabilities, Deferred Inflows, and Net Position

(Amounts in millions)

		June 30		
Assets and Deferred Outflows		**2014**	**2013 (as restated)**	**2012 (as restated)**
Utility plant, net	$	9,213	8,621	8,114
Restricted investments		641	634	639
Other noncurrent assets		2,301	2,523	2,135
Current assets		2,264	1,960	1,654
Deferred outflows		75	98	91
	$	14,494	13,836	12,633
Liabilities, Deferred Inflows, and Net Position				
Long-term debt, net of current portion	$	7,937	7,526	6,389
Other long-term liabilities		196	177	163
Current liabilities		890	836	895
Deferred inflows		177	138	161
		9,200	8,677	7,608
Fund net position:				
Net investment in capital assets		1,268	1,325	1,533
Restricted		1,563	1,554	1,525
Unrestricted		2,463	2,280	1,967
Total net position		5,294	5,159	5,025
	$	14,494	13,836	12,633

(Continued)

LOS ANGELES DEPARTMENT OF WATER AND POWER
POWER SYSTEM

Management's Discussion and Analysis

June 30, 2014 and 2013

Table 2 – Condensed Schedule of Revenues, Expenses, and Changes in Net Position

(Amounts in millions)

	Year ended June 30		
	2014	**2013**	**2012**
Operating revenues:			
Residential	$ 1,043	1,020	977
Commercial and industrial	2,233	2,062	2,040
Sales for resale	43	68	36
Other	1	13	29
Total operating revenues	3,320	3,163	3,082
Operating expenses:			
Fuel for generation and purchased power	(1,414)	(1,342)	(1,314)
Maintenance and other operating expenses	(950)	(925)	(922)
Depreciation and amortization	(466)	(418)	(394)
Total operating expenses	(2,830)	(2,685)	(2,630)
Operating income	490	478	452
Nonoperating revenues (expenses):			
Investment income	58	46	78
Federal bond subsidies	33	34	35
Other nonoperating revenues and expenses, net	21	20	14
Debt expense, net	(259)	(244)	(236)
Total nonoperating expenses	(147)	(144)	(109)
Income before capital contributions and transfers	343	334	343
Capital contributions	45	47	27
Transfers to the reserve fund of the City of Los Angeles	(253)	(247)	(250)
Increase in net position	135	134	120
Beginning balance of net position, as restated for the adoption of GASB Statement No. 65	5,159	5,025	4,905
Ending balance of net position	$ 5,294	5,159	5,025

(Continued)

Assets

Utility Plant

During fiscal years 2014 and 2013, the Power System capitalized $719 million and $1,284 million of additions, respectively, including transfers from construction work in progress to utility plant in service. Of the $719 million, $373 million, or 52% is related to distribution plant assets and mostly attributable to the Power Reliability Program (PRP) to improve distribution system reliability including replacement of aging poles, crossarms, cables, station equipment, and transformers. Other distribution system additions included construction of new Distribution Station 144 and installations of new business line facilities. In addition, $182 million, or 25% is related to general plant assets including replacement of the Customer Information System, new digital mobile radio system, server/system implementation, fleet purchases, and fiber optic network installations. In addition, $159 million or 22% is mostly related to generation plant assets including Castaic Modernization for Unit 1 and upgrade of 5 main generating units, repowering Haynes Generating Station Units 5 & 6, installing electrical auxiliary boilers for Haynes Unit 8, overhaul of auxiliary systems at Scattergood Generating Station Unit 1, and installation of solar system on City property. Of the $1,284 million during fiscal year 2013, $811 million, or 63% is mostly related to generation plant assets including repowering of Haynes Generating Station adding 6 simple-cycle gas turbines at $648 million or 80% of total capitalized in generation. The remaining capitalized included addition of Pine Tree Photovoltaic System, improvements to Haynes Unit 8, and upgrades of 5 main generating units at Castaic Power Plant. In addition, $322 million or 25% is related to distribution plant assets and mostly attributable to our PRP to improve distribution system reliability including replacement of aging poles, crossarms, cables, station equipment, and transformers. Other distribution system additions included construction of new business line facilities and installation of Substation Automation System (SAS) at various receiving and distribution stations. In addition, $63 million, or 5% is related to general plant assets including purchases of fleet equipment and installation of fiber optics.

Construction work in progress increased by $352 million in fiscal year 2014 and decreased by $327 million in fiscal year 2013. The 2014 increases are mostly attributable to capitalization of generation system assets including repowering of Scattergood Generating Station Unit 3, constructing Scattergood 230kv underground cable, Owens Valley Upper/Middle/Control Gorge generator upgrades, and improvements at Haynes Generating Station. Also, some increases in 2013 are attributable to Repowering of Scattergood Unit 3, replacement of Customer Information System (CIS), and Castaic Modernization. The 2013 decreases are mostly attributable to capitalization of generation system assets including repowering of Haynes generating station units 5 & 6, construction of Pine Tree Photovoltaic System, and Haynes Unit 8 overhaul. Also, some increases in 2013 are attributable to Repowering of Scattergood Unit 3, replacement of Customer Information System (CIS), and Castaic Modernization.

Additional information regarding the Power System's utility plant assets can be found in note 4 to the accompanying financial statements.

The tables that follow summarize the generating resources available to the Department as of June 30, 2014. These resources include those owned by the Department (either solely or jointly with other utilities) as well as resources available through long-term purchase agreements. Generating station capacity is measured in megawatts (MWs).

Table 3 – Department-Owned Generation Facilities

Type of fuel	Notional amount (number of facilities)	Number of units	Net maximum capability (MWs)	Net dependable capability (MWs)
Natural gas	4 (1)	27	3,474	3,373
Large hydro	1	7 (2)	1,247	1,175
Renewables	39	208 (3)	433 (4)	198
Subtotal	44	242	5,154	4,746
CDWR	—	—	(120) (5)	(54)
Total	44	242	5,034	4,692

(1) Consists of the following generating stations: Harbor Station, Haynes Station, Scattergood Station, and Valley Station.

(2) The Castaic Plant currently has six (1,075 MWs) out of seven units available due to ongoing modernization work scheduled to be completed by 2017.

(3) The Department-owned renewable resources in service include the Los Angeles Aqueduct, Owens Valley, and Owens Gorge small hydro units that qualify under the Department's renewable resource definition. Also included are microturbine units at the Lopez Canyon Landfill and Department built photovoltaic solar installations, the Pine Tree Wind Project, Linden Wind Farm, and a local small hydro plant. Not included in the counts are the units that were upgraded at the Castaic Plant. Also not included are the two Scattergood gas-fueled units that partially burn digester gas in which the output related to the digester gas also qualifies under the Department's renewable resource definition.

(4) Included are the 16 MWs of renewable energy generated at the Scattergood Station by burning digester gas from the Hyperion Treatment Plant.

(5) Energy payable to the California Department of Water Resources (CDWR) for energy generated at the Castaic Plant. This amount varies weekly up to maximum of 120 MWs.

Table 4 – Jointly Owned and Contracted Facilities

Type	Number of facilities	Net maximum capability (MWs)	Net dependable capability (MWs)
Large hydro	1	491 (1)	455
Nuclear	1	387 (2)	380
Coal	2	1,679 (3)	1,679
Natural gas	1	532	480
Renewables/DG	12,883 (4)	987	280
Total	12,888	4,076	3,274

(1) The Department's Hoover Plant contract entitlement is 25.16% of the Hoover total contingent capacity of 1,951 MWs. Current reduced lake level has reduced available capacity to about 468 MWs annual average.

(2) The Department's Palo Verde Station (PVNGS) entitlement is 9.66% of the maximum net plant capability of 4,003 MWs.

(3) The Department's current Intermountain Station (IPP) entitlement is 66.79% of the maximum net plant capability of 1,800 MWs. A portion of the IPP entitlement is subject to variable recall. The Department's Navajo Station entitlement is 21.20% of the maximum net plant capability of 2,250 MWs.

(4) The Department's contracted renewable resources in service include units at several landfill sites in the Los Angeles area; biogas fuel purchases outside of California; local hydro unit; wind farms in Wyoming, Oregon, Utah, and Washington; customer solar photovoltaic installations locally, and customer distributed generation (DG) units located in Los Angeles also provide energy resources.

Liabilities and Net Position

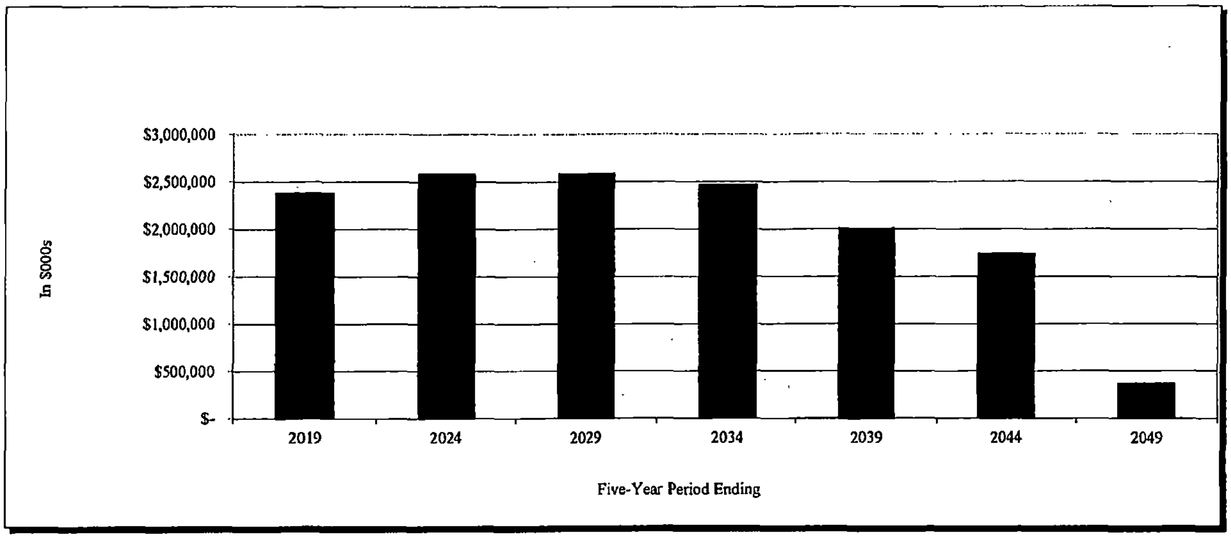
Long-Term Debt

As of June 30, 2014, the Power System's total outstanding long-term debt balance was approximately $8.165 billion. The increase of $390 million over the prior year's balance resulted from the sale of $522 million in Power System revenue bonds plus $44.4 million in issue premiums, net of underwriter's discount, offset by scheduled maturities of $132.4 million, and $44.7 million in net amortized premiums and discounts.

As of June 30, 2013, the Power System's total outstanding long-term debt balance was approximately $7.775 billion. The increase of $1.139 billion over the prior year's balance resulted from the sale of $1.761 billion in Power System revenue bonds plus $293.2 million in issue premiums, offset by scheduled maturities of $129 million, defeasance of $744 million in Power System revenue bonds, $42.9 million in net amortized premiums and discounts.

Outstanding principal, plus scheduled interest as of June 30, 2014, is scheduled to mature as shown in the chart below:

Chart: Debt Service Requirements



In addition, the Power System had $496.8 million and $490.3 million on deposit in trust funds restricted for the use of debt reduction as of June 30, 2014 and 2013, respectively.

In June 2014, Standard & Poor's Rating Services, Moody's Investors Service, and Fitch Ratings affirmed the Power System's bond rating of AA-, Aa3, and AA-, respectively, due to the Power System's broad revenue stream and a competitive power supply portfolio that has historically provided competitive retail electricity rates and evident strategic focus on positioning the utility to improve system reliability while meeting state mandated greenhouse emission rules and renewable energy standards. Additional information regarding the Power System's long-term debt can be found in note 10 to the financial statements.

Current Assets

During fiscal year 2014, current assets increased $304 million. Cash and cash equivalents increased $178 million due to reimbursements from the construction fund for capital expenditures, the current portion of under recovered costs increased $87 million, a receivable, due from the City of Los Angeles' Department of Water and Power's Water Revenue Fund (Water System) for materials and services increased $16 million, prepayments and other current assets increased by $25 million, offset by a $4 million decrease in customer and other accounts receivables and a $4 million decrease in the current portion of long-term notes receivable.

During fiscal year 2013, current assets increased $308 million. Cash and cash equivalents increased $199 million due to reimbursements from the construction fund for capital expenditures, customer, and other accounts receivables increased $46 million due to higher rates and higher consumption, the current portion of under-recovered costs increased $27 million, a receivable, due from the Water System for materials and services increased $24 million, the current portion of long-term notes receivable increased $8 million, prepayments and other current assets increased by $11 million, offset by a $7 million decrease in materials and fuel.

Other Noncurrent Assets

During fiscal year 2014, other noncurrent assets decreased $215 million due to a decrease of $254 million of restricted cash and cash equivalents for construction purposes, $67 million decrease in long-term notes receivable due to maturities and a $29 million decrease in under-recovered costs. These decreases were offset by a $113 million increase in regulatory assets due to greater customer participation in the Departments' Solar Incentive and Energy Efficiency programs, an increase of $16 million in the postemployment asset due to higher funding than actuarially required contributions, and a $6 million increase in restricted investments.

During fiscal year 2013, other noncurrent assets increased $423 million due to an increase of $426 million of restricted cash and cash equivalents for construction purposes, $83 million increase in regulatory assets due to greater customer participation in the Departments' Solar Incentive and Energy Efficiency programs and an increase of $21 million in the postemployment asset due to higher funding than actuarially required contributions. These increases were offset by reductions in Long-term Notes Receivable of $68 million due to maturities and under recovered costs of $39 million.

Changes in Net Position

Operating Revenues

The operating revenues of the Power System are generated from wholesale and retail customers. There are four major customer categories of retail revenue. These categories include residential, commercial, industrial, and other, which includes public street lighting. Table 5 summarizes the percentage contribution of retail revenues from each customer segment in fiscal years 2014 and 2013:

Table 5 – Revenue and Percentage of Revenue by Customer Class

(Amounts in thousands)

	Fiscal year 2014		Fiscal year 2013	
	Revenue	**Percentage**	**Revenue**	**Percentage**
Type of customer:				
Residential	$ 1,042,641	32%	$ 1,019,656	33%
Commercial	1,964,465	60	1,826,307	59
Industrial	268,413	8	235,330	8
Other	1,492	—	13,445	—
	$ 3,277,011	100%	$ 3,094,738	100%

While commercial customers consume the most electricity, residential customers represent the largest customer class. As of June 30, 2014 and 2013, the Power System had approximately 1.5 million customers. As shown in Table 6, 1.4 million and 1.3 million, or 91% and 87%, respectively, of total customers were in the residential customer class in fiscal years 2014 and 2013.

Table 6 – Number of Customers and Percentage of Customers by Customer Class

(Amounts in thousands)

	Fiscal year 2014		Fiscal year 2013	
	Number	Percentage	Number	Percentage
Type of customer:				
Residential	1,368	91%	1,338	87%
Commercial	117	8	121	12
Industrial	11	1	12	1
Other	7	—	8	—
	1,503	100%	1,479	100%

Fiscal Year 2014

Retail revenues increased $182 million from fiscal year 2013. The increase in retail revenue was mainly due to an average rate increase of 9%, which includes a 6% increase in the Incremental Energy Cost Adjustment (iECA) Factor. The iECA factor in June 2013 was $0.05854 cents/kWh and increased to $0.06200 cents/kWh in June 2014.

Fiscal Year 2013

Retail revenues increased $49 million from fiscal year 2012. The increase in retail revenue was mainly due to an increase in consumption of approximately 511 gigawatts year over year and an increase in the Incremental Energy Cost Adjustment Factors that became effective during November 2012. The ECA rate during fiscal year 2012 was frozen at $0.0569/kWh; by June 2013, the rates were $0.0609/kWh.

Operating Expenses

Fuel for generation and purchased power are two of the largest expenses that the Power System incurs each fiscal year. Fuel for generation expense includes the cost of fuel that is used to generate energy. The majority of fuel costs include the cost of natural gas, coal, and nuclear fuel.

Purchased power expense includes the cost of buying power on the open market and paying the current portion of the Power System's purchased power contracts. Under these purchase power contracts, the Department has an entitlement to the energy that is produced at various generating stations and an entitlement to the use of various transmission facilities. Most of these contracts require the Department to pay for these services regardless of whether the energy or transmission is used. These types of contracts are referred to as "take-or-pay" contracts.

Depreciation expense is computed using the straight-line method based on service lives for all projects completed after July 1, 1973, and for all office and shop structures, related furniture and equipment, and transportation and construction equipment. Depreciation for facilities completed prior to July 1, 1973 is computed using the 5% sinking-fund method based on estimated service lives. The Department uses the composite method of depreciation and, therefore, groups assets into composite groups for purposes of calculating depreciation expense. Estimated service lives range from 5 to 75 years. Amortization expense for computer software is computed using the straight-line method over 5 to 15 years.

The table below summarizes the Power System's operating expenses during fiscal years 2014 and 2013:

Table 7 – Operating Expenses and Percentage of Expense by Type of Expense

(Amounts in thousands)

	Fiscal year 2014		Fiscal year 2013	
	Expense	**Percentage**	**Expense**	**Percentage**
Type of expense:				
Fuel for generation	$ 436,643	15%	$ 446,450	17%
Purchased power	977,187	35	895,092	33
Other operating expenses	654,809	23	623,033	23
Maintenance	295,218	10	301,674	11
Depreciation and amortization	466,526	17	418,485	16
	$ 2,830,383	100%	$ 2,684,734	100%

Fiscal Year 2014

Fiscal year 2014 operating expenses were $146 million higher as compared to fiscal year 2013, driven primarily by a $82 million increase in purchased power costs, a $48 million increase in depreciation and amortization expense, and a $32 million increase in other operating expenses, offset by lower fuel for generation costs, and maintenance expenses.

The $82 million increase in purchased power costs can be primarily attributed to a higher volume of economy purchases year over year and energy from the Apex power project. The $48 million increase in depreciation and amortization expense is primarily due to capital improvements in production plant, as well as additional amortization expense from the regulatory assets. The $32 million increase in other operating expenses is due to higher other production ($15 million), transmission ($4 million), customer accounting ($4 million), administrative and general ($6 million), distribution ($1 million), and marketing ($1 million) expenses.

The decrease in maintenance expense was mainly due to lower maintenance costs associated with production plant ($6 million) and transmission plant ($5 million) capital assets offset by an increase in maintenance costs for production plant – hydraulic ($2 million) and distribution plant ($1 million) capital assets.

Fiscal Year 2013

Fiscal year 2013 operating expenses were $55 million higher as compared to fiscal year 2012, driven primarily by a $43 million increase in fuel for generation, a $24.5 million increase in depreciation and amortization expense, and a $5.6 million increase in other operating expenses, offset by lower purchased power, and maintenance expenses.

The $43 million increase in fuel for generation can be primarily attributed to higher consumption and higher natural gas prices. The $24.5 million increase in depreciation and amortization expense is primarily due to capital improvements in distribution plant, as well as additional amortization expense from the regulatory assets. The $5.6 million increase in other operating expenses is due to higher administrative and general expenses.

The decrease in maintenance expense was mainly due to lower maintenance costs associated with production plant ($6.0 million) and transmission plant ($18.9 million) capital assets offset by an increase in maintenance costs for distribution plant ($19.4 million) and other production plant ($2.4 million) capital assets.

Nonoperating Revenues and Expenses

Fiscal Year 2014

The major nonoperating activities of the Power System for fiscal year 2014 included the transfer of $253 million to the City's General Fund, interest income earned on investments of $58 million, $33 million in federal bond subsidies, and $259 million in debt expenses.

The transfer to the City is based on 8% of the previous year's operating revenues. Operating revenues for fiscal year 2013 were $3.162 billion, which generated a city transfer of $253 million.

The $12 million increase in investment income is due mainly to changes in market values of investments.

The $16 million increase in debt expenses is mainly due to the interest expense for new money bonds issued during the fiscal year offset by lower capitalized interest (AFUDC) year over year due to the transfer of major CWIP projects to utility plant accounts.

Fiscal Year 2013

The major nonoperating activities of the Power System for fiscal year 2013 included the transfer of $247 million to the City's General Fund, interest income earned on investments of $46 million, $34 million in federal bond subsidies, and $241 million in debt expenses.

The transfer to the City is based on 8% of the previous year's operating revenues. Operating revenues for fiscal year 2012 were $3.082 billion, which generated a city transfer of $247 million.

The $32 million decrease in investment income is due to changes in market values of investments and decreases in funds held in the related restricted investments.

The $1.5 million decrease in federal bond subsidies is directly related to interest payment subsidies that are received from the U.S. Treasury.

(Continued)

The $4.8 million increase in other nonoperating income is mainly due to insurance reimbursements and a gain from the sale of land.

The $5.0 million increase in interest on debt is mainly due to interest expense for new money bond issuances offset by amortization costs and interest savings from debt refinancing undertaken by the Power System during fiscal year 2013.

LOS ANGELES DEPARTMENT OF WATER AND POWER
POWER SYSTEM

Statements of Net Position

June 30, 2014 and 2013

(Amounts in thousands)

Assets and Deferred Outflows		2014	2013
Noncurrent assets:			
Utility plant:			
Generation	$	5,313,866	5,158,303
Transmission		1,095,472	1,089,835
Distribution		7,031,862	6,659,814
General		1,541,640	1,365,206
		14,982,840	14,273,158
Accumulated depreciation		(7,298,042)	(6,853,589)
		7,684,798	7,419,569
Construction work in progress		1,235,945	884,378
Nuclear fuel, at amortized cost		42,931	44,686
Natural gas field, net		248,923	272,157
		9,212,597	8,620,790
Restricted investments		640,094	633,903
Cash and cash equivalents – restricted		193,701	448,184
Long-term notes and other receivables, net of current portion		703,576	770,495
Under-recovered costs		244,712	273,839
Regulatory assets		492,104	378,752
Net postemployment asset		668,451	652,439
Total noncurrent assets		12,155,235	11,778,402
Current assets:			
Cash and cash equivalents – unrestricted		775,890	597,525
Cash and cash equivalents – restricted		414,072	414,369
Cash collateral received from securities lending transactions		1,419	3,164
Customer and other accounts receivable, net of $90,000 and $18,900 allowance for losses for 2014 and 2013, respectively		402,494	398,458
Current portion of long-term notes receivable		69,838	73,759
Current portion of under-recovered costs		114,290	27,218
Due from Water System		40,314	24,059
Accrued unbilled revenue		175,162	175,635
Materials and fuel		163,484	163,088
Prepayments and other current assets		106,850	82,238
Total current assets		2,263,813	1,959,513
Total assets		14,419,048	13,737,915
Deferred outflows on derivative instruments		48,517	67,275
Deferred outflows on debt refunding		26,796	30,498
Total assets and deferred outflows	$	14,494,361	13,835,688

(Continued)

LOS ANGELES DEPARTMENT OF WATER AND POWER
POWER SYSTEM

Statements of Net Position

June 30, 2014 and 2013

(Amounts in thousands)

Net Position, Liabilities, and Deferred Inflows	**2014**	**2013**
Net position:		
Net investment in capital assets	$ 1,268,339	1,324,962
Restricted:		
Debt service	606,509	624,468
Capital projects	126,521	122,584
Other postemployment benefits	668,451	652,439
Other purposes	160,508	154,891
Unrestricted	2,463,312	2,279,796
Total net position	5,293,640	5,159,140
Long-term debt, net of current portion	7,937,180	7,525,264
Other noncurrent liabilities:		
Accrued liabilities	5,327	7,047
Accrued workers' compensation claims	56,650	52,220
Derivative instrument liabilities	48,517	67,275
Net pension liability	85,534	50,773
Total other noncurrent liabilities	196,028	177,315
Current liabilities:		
Current portion of long-term debt	227,575	249,245
Accounts payable and accrued expenses	394,150	333,422
Accrued interest	159,647	145,338
Accrued employee expenses	107,939	104,477
Obligations under securities lending transactions	1,419	3,164
Total current liabilities	890,730	835,646
Total liabilities	9,023,938	8,538,225
Deferred inflows from regulated business activities	176,783	138,323
Total net position, liabilities, and deferred inflows	$ 14,494,361	13,835,688

See accompanying notes to financial statements.

LOS ANGELES DEPARTMENT OF WATER AND POWER
POWER SYSTEM

Statements of Revenues, Expenses, and Changes in Net Position

Years ended June 30, 2014 and 2013

(Amounts in thousands)

		2014	2013
Operating revenues:			
Residential	$	1,042,641	1,019,656
Commercial and industrial		2,232,878	2,061,637
Sales for resale		42,809	67,764
Other		59,383	36,329
Uncollectible accounts		(57,891)	(22,884)
		3,319,820	3,162,502
Operating expenses:			
Fuel for generation		436,643	446,450
Purchased power		977,187	895,092
Maintenance and other operating expenses		950,027	924,707
Depreciation and amortization		466,526	418,485
		2,830,383	2,684,734
Operating income		489,437	477,768
Nonoperating revenues (expenses):			
Investment income		58,099	46,076
Federal bond subsidies		33,417	33,614
Other nonoperating income		23,033	22,342
		114,549	102,032
Other nonoperating expenses		(2,513)	(2,480)
		112,036	99,552
Debt expenses:			
Interest on debt		277,848	276,974
Allowance for funds used during construction		(18,636)	(33,672)
		259,212	243,302
Income before capital contributions and transfers		342,261	334,018
Capital contributions		45,239	46,860
Transfers to the reserve fund of the City of Los Angeles		(253,000)	(246,534)
Increase in net position		134,500	134,344
Net position:			
Beginning of period, as restated		5,159,140	5,024,796
End of period	$	5,293,640	5,159,140

See accompanying notes to financial statements.

LOS ANGELES DEPARTMENT OF WATER AND POWER
POWER SYSTEM

Statements of Cash Flows

Years ended June 30, 2014 and 2013

(Amounts in thousands)

		2014	2013
Cash flows from operating activities:			
Cash receipts:			
Cash receipts from customers	$	3,353,723	3,168,084
Cash receipts from customers for other agency services		601,332	620,256
Cash receipts from interfund services provided		589,327	484,169
Cash disbursements:			
Cash payments to employees		(548,956)	(565,396)
Cash payments to suppliers		(1,668,524)	(1,581,590)
Cash payments for interfund services used		(733,801)	(710,161)
Cash payments to other agencies for fees collected		(603,596)	(616,206)
Other operating cash payments		(46,748)	(38,079)
Net cash provided by operating activities		942,757	761,077
Cash flows from noncapital financing activities:			
Payments to the reserve fund of the City of Los Angeles		(253,000)	(246,534)
Interest paid on noncapital revenue bonds		(233)	(589)
Net cash used in noncapital financing activities		(253,233)	(247,123)
Cash flows from capital and related financing activities:			
Additions to plant and equipment, net		(1,112,681)	(953,376)
Capital contributions		65,485	47,728
Principal payments and maturities on long-term debt		(132,382)	(129,250)
Proceeds from issuance of bonds and revenue certificates		566,419	1,294,185
Debt interest payments		(303,394)	(291,439)
Federal bond subsidies		33,417	33,614
Net cash provided by (used in) capital and related financing activities		(883,136)	1,462
Cash flows from investing activities:			
Purchases of investment securities		(698,514)	(872,717)
Sales and maturities of investment securities		697,696	870,251
Proceeds from notes receivable		66,919	68,260
Investment income		51,096	45,018
Net cash provided by investing activities		117,197	110,812
Net (decrease) increase in cash and cash equivalents		(76,415)	626,228
Cash and cash equivalents:			
Cash and cash equivalents at July 1 (including $862,553 and $415,955 reported in restricted accounts, respectively)		1,460,078	833,850
Cash and cash equivalents at June 30 (including $607,773 and $862,553 reported in restricted accounts, respectively)	$	1,383,663	1,460,078

(Continued)

LOS ANGELES DEPARTMENT OF WATER AND POWER
POWER SYSTEM

Statements of Cash Flows

Years ended June 30, 2014 and 2013

(Amounts in thousands)

		2014	2013
Reconciliation of operating income to net cash provided by operating activities:			
Operating income	$	489,437	477,768
Adjustments to reconcile operating income to net cash provided by operating activities:			
Depreciation and amortization		466,526	418,485
Depletion expense		23,564	26,176
Amortization of nuclear fuel		13,934	13,859
Provision for losses on customer and other accounts receivables		57,891	22,884
Changes in assets and liabilities:			
Customer and other accounts receivable		(76,621)	(68,780)
Accrued unbilled revenue		473	(2,402)
Under-recovered costs		29,127	38,534
Current portion under-recovered costs		(87,072)	(27,218)
Materials and fuel		(396)	6,751
Regulatory assets		(113,352)	(82,529)
Due from water system		(16,254)	(24,059)
Accounts payable and accrued expenses		96,211	12,883
Deferred inflows		38,461	(22,655)
Due to water services		—	(64,978)
Net pension liability		34,761	32,564
Net other postemployment benefit asset		(16,012)	(20,959)
Prepayments and other		2,079	24,753
Net cash provided by operating activities	$	942,757	761,077

See accompanying notes to financial statements.

(1) Summary of Significant Accounting Policies

The Department of Water and Power of the City of Los Angeles (the Department) exists as a separate proprietary department of the City of Los Angeles (the City) under and by virtue of the City Charter enacted in 1925 and as revised effective July 2000. The Department's Power Revenue Fund (the Power System) is responsible for the generation, transmission, and distribution of electric power for sale in the City. The Power System is operated as an enterprise fund of the City.

(a) Method of Accounting

The accounting records of the Power System are maintained in accordance with U.S. generally accepted accounting principles (GAAP) for governmental entities. The financial statements have been prepared using the economic resources measurement focus and the accrual basis of accounting. The Power System is accounted for as an enterprise fund and applies all applicable Governmental Accounting Standards Board (GASB) pronouncements in its accounting and reporting.

The financial statements of the Power System are intended to present the net position, and the changes in net position, and cash flows of only that portion of the business-type activities and each major fund of the City of Los Angeles, California that is attributable to the transactions of the Power System. They do not purport to, and do not, present fairly the net position of the City of Los Angeles, California as of June 30, 2014 and 2013, the changes in its financial position or, where applicable, its cash flows for the years then ended, in conformity with GAAP.

The Department's rates are determined by the Board of Water and Power Commissioners (the Board) and are subject to review and approval by the Los Angeles City Council (City Council). As a regulated enterprise, the Department follows the regulatory accounting criteria set forth per the GASB Codification (GASB Statement No. 62), which requires that the effects of the rate-making process be recorded in the financial statements. Such effects primarily concern the time at which various items enter into the determination of changes in net position. Accordingly, the Power System records various regulatory assets and liabilities to reflect the Board's actions. Regulatory liabilities are recorded in deferred inflows and regulatory assets are included as regulatory assets and under-recovered costs in the statement of net position. Management believes that the Power System meets the criteria for continued application, but will continue to evaluate its applicability based on changes in the regulatory and competitive environment (see notes 3 and 14(d)(i)).

(b) Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

(c) Utility Plant

The costs of additions to utility plant and replacements of retired units of property are capitalized. Costs include labor, materials, an allowance for funds used during construction (AFUDC), and allocated indirect charges, such as engineering, supervision, transportation and construction equipment, retirement plan contributions, healthcare costs, and certain administrative and general expenses. The costs of maintenance, repairs, and minor replacements are charged to the appropriate operations and maintenance expense accounts.

(d) Intangibles

The Department follows GASB Statement No. 51, *Accounting and Financial Reporting for Intangible Assets* (GASB Statement No. 51), which requires that an intangible asset be recognized in the statement of net position only if it is considered identifiable. Additionally, it establishes a specified-conditions approach to recognize intangible assets that are internally generated. Effectively, outlays associated with the development of such assets are not capitalized until certain criteria are met. Outlays incurred prior to meeting these criteria are expensed as incurred. The capitalized amounts are included in general utility plant on the statement of net position.

(e) Impairment of Long-Lived Assets

The Department follows GASB Statement No. 42, *Accounting and Financial Reporting for Impairment of Capital Assets and for Insurance Recoveries* (GASB Statement No. 42). Governments are required to evaluate prominent events or changes in circumstances affecting capital assets to determine whether impairment of a capital asset has occurred. A capital asset is considered impaired when its service utility has declined significantly and unexpectedly. Under GASB Statement No. 42, impaired capital assets that will no longer be used by the government should be reported at the lower of carrying value or fair value. Impairment losses on capital assets that will continue to be used by the government should be measured using the method that best reflects the cause of the diminished service utility of the capital asset.

(f) Depreciation and Amortization

Depreciation expense is computed using the straight-line method based on service lives for all projects completed after July 1, 1973, and for all office and shop structures, related furniture and equipment, and transportation and construction equipment. Depreciation for facilities completed prior to July 1, 1973 is computed using the 5.0% sinking-fund method based on estimated service lives. The Department uses the composite method of depreciation and, therefore, groups assets into composite groups for purposes of calculating depreciation expense. Estimated service lives range from 5 to 75 years. Amortization expense for computer software is computed using the straight-line method over 5 to 15 years. Depreciation and amortization expense as a percentage of average depreciable utility plant in service was 3.2% and 3.1% for fiscal years 2014 and 2013, respectively.

(g) Nuclear Decommissioning

The Department owns a 5.70% direct ownership interest in the Palo Verde Nuclear Generating Station (PVNGS). In addition, through its participation in the Southern California Public Power Authority (SCPPA), the Department is party to a contract for an additional 3.95% of the output of PVNGS. Nuclear decommissioning costs associated with the Power System's output entitlement are included in purchased power expense (see note 6).

Decommissioning of PVNGS is expected to commence subsequent to the year 2044, since the Nuclear Regulatory Commission (the NRC) approved a request for license extension in April 2011. As of April 28, 2014, all of the owners of PVNGS have executed the amendment to the participation agreement to extend the term of the agreement to cover the license extension of PVNGS. The total cost to decommission the Power System's direct ownership interest in PVNGS is estimated to be $137 million in 2013 dollars. This estimate is based on an updated site-specific study prepared by an independent consultant in 2013. As of June 30, 2014 and 2013, the Power System has recorded $146.1 million and $142.1 million, respectively, to accumulated depreciation to provide for the decommissioning liability.

Prior to December 1999, the Power System contributed $70.2 million to external trusts established in accordance with the PVNGS participation agreement and NRC requirements. During fiscal year 2000, the Department suspended contributing additional amounts to the trust funds, as management believes that contributions made, combined with reinvested earnings, will be sufficient to fully fund the Department's share of decommissioning costs. The Department will continue to reinvest its investment income on the trust investments into the decommissioning trusts. The balance in the decommissioning funds increased in fiscal year 2014 by $3.9 million, after decreasing by $1.6 million in fiscal year 2013 due to market value losses. Decommissioning funds, which are included in restricted investments, totaled $126.5 million and $122.6 million as of June 30, 2014 and 2013 (at fair value), respectively. The Department's current accounting policy recognizes any realized and unrealized investment earnings from nuclear decommissioning trust funds as a component of accumulated depreciation.

(h) Nuclear Fuel

Nuclear fuel is amortized and charged to fuel for generation on the basis of actual thermal energy produced relative to total thermal energy expected to be produced over the life of the fuel. Under the provisions of the Nuclear Waste Policy Act of 1982, the federal government assesses each utility with nuclear operations, including the Power System, $1 per megawatt hour of nuclear generation. The Power System includes this charge as a current year expense in fuel for generation. See note 14 for discussion of spent nuclear fuel disposal.

(i) Natural Gas Field

In July 2005, the Power System acquired approximately a 74.5% ownership interest in gas properties located in Pinedale, Wyoming. The Power System uses the successful-efforts method of accounting for its investment in gas producing properties. Costs to acquire the mineral interest in gas producing properties, to drill and equip exploratory wells that find proven reserves, and to drill and equip development wells are capitalized. Costs to drill exploratory wells that do not find proven reserves are expensed. Capitalized costs of gas producing properties are depleted by the unit-of-production method based on the estimated future production of the proven wells.

Depletion expense related to the gas field is recorded as a component of fuel for generation expense. During fiscal years 2014 and 2013, the Power System recorded $23.6 million and $26.2 million of depletion expense, respectively.

(j) Cash and Cash Equivalents

As provided for by the State of California Government Code (the Code), the Power System's cash is deposited with the City Treasurer in the City's general investment pool for the purpose of maximizing interest earnings through pooled investment activities. Cash and cash equivalents in the City's general investment pool are reported at fair value and changes in unrealized gains and losses are recorded in the statements of revenues, expenses, and changes in net position. Interest earned on such pooled investments is allocated to the participating funds based on each fund's average daily cash balance during the allocation period. The City Treasurer invests available funds of the City and its independent operating departments on a combined basis. The Power System classifies all cash and cash equivalents that are restricted either by creditors, the Board, or by law, as restricted cash and cash equivalents in the statement of net position. The Power System considers its portion of pooled investments in the City's pool to be cash and cash equivalents and the unspent construction funds as long-term restricted cash as cash equivalents.

At June 30, 2014 and 2013, restricted cash and cash equivalents include the following (amounts in thousands):

		June 30	
		2014	**2013**
Bond redemption and interest funds	$	270,273	280,470
Self-insurance fund		143,799	133,899
Cash and cash equivalents – current portion		414,072	414,369
Construction funds – classified as long-term restricted cash		193,701	448,184
Total restricted cash and cash equivalents	$	607,773	862,553

(k) Materials and Fuel

Materials and supplies are recorded at average cost. Fuel is recorded at lower of cost or market, on an average-cost basis.

(l) Accrued Unbilled Revenue

Accrued unbilled revenue is the receivable for estimated energy sales during the period for which service has been provided but the customer has not been billed.

(m) Restricted Investments

Restricted investments include primarily commercial paper, U.S. government and governmental agency securities, and corporate bonds. Investments are reported at fair value and changes in unrealized gains and losses are recorded in the statements of revenues, expenses, and changes in net

(Continued)

position except for Nuclear Decommissioning Trust Funds. The stated fair value of investments is generally based on published market prices or quotations from major investment dealers (see note 7).

(n) Accrued Employee Expenses

Accrued employee expenses include accrued payroll and an estimated liability for vacation leave, sick leave, and compensatory time, which is accrued when employees earn the rights to the benefits. Below is a schedule of accrued employee expenses as of June 30, 2014 and 2013 (amounts in thousands):

		2014	2013
Type of expenses:			
Accrued payroll	$	30,957	27,122
Accrued vacation		49,583	48,648
Accrued sick leave		11,835	11,883
Compensatory time		15,564	16,824
Total	$	107,939	104,477

(o) Debt Expenses

Debt premiums and discounts are capitalized and amortized to debt expense using the effective-interest method over the lives of the related debt issues. Gains and losses on refundings related to bonds redeemed by proceeds from the issuance of new bonds are amortized to interest expense using the effective-interest method over the shorter of the life of the new bonds or the remaining term of the bonds refunded.

(p) Accrued Workers' Compensation Claims

Liabilities for unpaid workers' compensation claims are recorded at their net present value (see note 13).

(q) Customer Deposits

Customer deposits represent deposits collected from customers upon opening of new accounts. These deposits are obtained when the customer does not have a previously established credit history with the Department. Original deposits plus interest are paid to the customer once a satisfactory payment history is maintained, generally after one to three years.

The Department's Water Revenue Fund (Water System) is responsible for collection, maintenance, and refunding of these deposits for all the Department customers, including those of the Power System. As such, the Water System's statement of net position includes a deposit liability of $113.3 million and $92 million as of June 30, 2014 and 2013, respectively, for all customer deposits collected. In the event that the Water System defaults on refunds of such deposits, the Power System would be required to pay amounts it owes its customers.

(r) *Revenues*

The Power System's rates are established by a rate ordinance, which is approved by the City Council. The Power System sells energy to the City's other departments at rates provided in the ordinance. The Power System recognizes energy costs in the period incurred and accrues for estimated energy sold but not yet billed.

Through a set of rate ordinances, the Power System bills its revenue through fixed and pass-through factors. As of November 11, 2012, pass-through factors consist of Capped Energy Cost Adjustment Factor (CECAF), Variable Energy Adjustment Factor (VEAF), Variable Renewable Portfolio Standard Energy Adjustment Factor (VRPSEAF), Capped Renewable Portfolio Standard Energy Adjustment Factor (CRPSEAF), Reliability Cost Adjustment Factor (RCAF), Incremental Reliability Cost Adjustment Factor (IRCAF), and Energy Subsidy Adjustment Factor (ESAF).

On October 1, 2006, the Energy Cost Adjustment Factor (ECAF) and now known as the CECAF was unfrozen from its 2.94 cents/kWh charge. This change allows the Power System to increase or decrease the factor on a quarterly basis to adjust for fuel and purchased power expenses incurred in the production of energy. On November 10, 2012, CECAF has reached 5.69 cents/kWh and is once again frozen (or capped) by the City Council. To continue to recover fuel and purchased power expenses, the City Council enacted the VEAF, VRPSEAF, and CRPSEAF, which are aggregately known as the Incremental Energy Cost Adjustment Factors (IECAFs) to supplement the CECAF that is capped. The VEAF is used to recover nonrenewable energy expenses; the VRPSEAF is used to recover variable renewable energy expenses; and the CRPSEAF is used to recover fixed renewable energy expenses (i.e., debt service and O&M).

On May 1, 2008, the RCAF was established to recover expenses incurred on Power System reliability related work and was set at 0.1 cents/kWh for residential customers or 0.32 cents/kW for commercial customers. The RCAF reached its maximum allowable limit of 0.3 cents/kWh for residential customers and 0.96 cents/kWh for commercial customers in fiscal year 2010–11. To allow further recovery of reliability related expenses, the City Council established the IRCAF on November 11, 2012. Currently, the IRCAF is a fixed pass-through predetermined for fiscal years 2012–13 and 2013–14.

On November 11, 2012, a pass-through factor, Base Rate Revenue Target Adjustment Factor (BRRTAF) was established by the City Council to adjust base revenue collection (nonpass-through revenue) to reach its annual target. This action will decouple the risks to the Department on retail load sales, which are dependent on economic health or weather-driven events. Effectively, the Department is assured its revenue requirement to operate the Power System.

On April 1, 1998, the ESAF was frozen and continued to be frozen at 0.147 cents/kWh for residential customers and 0.46 cents/kWh for commercial customers.

As of June 30, 2014 and 2013, the amount of under-recovered costs, including the CECAF and the RCAF was $244.7 million and $273.8 million, respectively. The balances for the CECAF and the RCAF are recorded as noncurrent assets in the statement of net position. As of June 30, 2014, the amount of under-recovered costs, including the VEAF, VRPSEAF, CRPSEAF, and the BRRTAF was $114.3 million. The balances for the VEAF, VRPSEAF, CRPSEAF, and the BRRTAF are recorded as current assets in the statement of net position.

(s) Capital Contributions

Capital contributions and other grants received by the Department for constructing utility plant and other activities are recognized when all applicable eligibility requirements, including time requirements, are met.

(t) Allowance for Funds Used during Construction (AFUDC)

An AFUDC charge represents the cost of borrowed funds used for the construction of utility plant. Capitalized AFUDC is included as part of the cost of utility plant and as a reduction of debt expenses. As of June 30, 2014 and 2013, the average AFUDC rates were 4.0% and 3.7%, respectively.

(u) Use of Restricted and Unrestrictive Resources

The Power System's policy is to use unrestricted resources prior to restricted resources to meet expenses to the extent that it is prudent from an operational perspective. Once it is not prudent, restricted resources will be utilized to meet intended obligations.

(2) Recent Accounting Pronouncements

(a) GASB Statement No. 62

In December 2010, the GASB issued Statement No. 62, *Codification of Accounting and Financial Reporting Guidance Contained in Pre-November 30, 1989 FASB and AICPA Pronouncements* (GASB Statement No. 62). The requirements in this Statement will improve financial reporting by contributing to the GASB's efforts to codify all sources of generally accepted accounting principles for state and local governments so that they derive from a single source. The Power System adopted GASB Statement No. 62 effective July 1, 2012 and there was no material impact of this pronouncement on the financial statements.

(b) GASB Statement No. 63

In June 2011, the GASB issued Statement No. 63, *Financial Reporting of Deferred Outflows of Resources, Deferred Inflows of Resources, and Net Position* (GASB Statement No. 63). The requirements of this Statement will improve financial reporting by standardizing the presentation of deferred outflows of resources and deferred inflows of resources and their effects on a government's net position. It alleviates uncertainty about reporting those financial statement elements by providing guidance where none previously existed. The Power System adopted GASB Statement No. 63 effective July 1, 2012 and the primary change to the financial statements was changing references from net assets to net position.

(c) *GASB Statement No. 64*

In June 2011, the GASB issued Statement No. 64, *Derivative Instruments: Application of Hedge Accounting Termination Provisions – an amendment of GASB Statement No. 53* (GASB Statement No. 64). The objective of this Statement is to clarify whether an effective hedging relationship continues after the replacement of a swap counterparty or a swap counterparty's credit support provider. This Statement sets forth criteria that establish when the effective hedging relationship continues and hedge accounting should continue to be applied. The Power System adopted GASB Statement No. 64 effective July 1, 2012 and there was no material impact of this pronouncement on the financial statements.

(d) *GASB Statement No. 65*

In March 2012, the GASB issued Statement No. 65, *Items Previously Reported as Assets and Liabilities* (GASB Statement No. 65). The requirements of this Statement establishes accounting and financial reporting standards that reclassify, as deferred outflows of resources or deferred inflows of resources, certain items that were previously reported as assets and liabilities and recognizes, as outflows of resources or inflows of resources, certain items that were previously reported as assets and liabilities. It will improve financial reporting by clarifying the appropriate use of the financial statement elements deferred outflows of resources and deferred inflows of resources to ensure consistency in financial reporting. The provisions of this Statement are effective for financial statements for periods beginning after December 15, 2012. On July 1, 2013, the Power System adopted GASB Statement No. 65 which caused the Power System to restate its prior year net position by the amount of the unamortized debt issuance costs, as these costs are now required to be recognized as an expense in the period incurred. The previously reported net position as of July 1, 2012 was reduced by $88.2 million to a restated balance of $5,024.8 million. In addition, 2013 net position decreased by $2.1 million.

(e) *GASB Statement No. 67*

In June 2012, the GASB issued Statement No. 67, *Financial Reporting for Pension Plans – an amendment of GASB Statement No. 25* (GASB Statement No. 67). The requirements of this Statement will improve financial reporting primarily through enhanced note disclosures and schedules of required supplementary information that will be presented by the pension plans that are within its scope. The new information will enhance the decision-usefulness of the financial reports of these pension plans, their value for assessing accountability, and their transparency by providing information about measures of net pension liabilities and explanations of how and why those liabilities changed from year to year. The Power System adopted this statement in fiscal year 2014. This statement has no impact on the Power System's financial statements.

(f) *GASB Statement No. 68*

In June 2012, the GASB issued Statement No. 68, *Accounting and Financial Reporting for Pension Plans – an amendment of GASB Statement No. 27* (GASB Statement No. 68). This Statement establishes standards for measuring and recognizing liabilities, deferred outflows of resources, and deferred inflows of resources, and expense/expenditures. For defined-benefit pensions, this

Statement identifies the methods and assumptions that should be used to project benefit payments, discount projected benefit payments to their actuarial present value, and attribute that present value to periods of employee service. The provisions of this Statement are effective for financial statements for periods beginning after June 15, 2014. The Power System is currently evaluating the impact of this pronouncement on the financial statements.

(g) GASB Statement No. 70

In April 2012, the GASB issued Statement No. 70, *Accounting and Financial Reporting for Nonexchange Financial Guarantees* (GASB Statement No. 70). This Statement establishes standards for financial guarantees that are nonexchange transactions extended or received by state or local government. A nonexchange financial guarantee is a guarantee of an obligation of a legally separate entity or individual, including a blended or discretely presented component unit, which requires the guarantor to indemnify a third-party obligation holder under specific conditions. The Power System implemented this statement in fiscal year 2014. This statement has no material impact on the Power System's financial statements.

(3) Regulatory Matters

(a) Federal Energy Legislation of 2005

On August 8, 2005, the Energy Policy Act of 2005 (EP Act) was enacted, the first comprehensive energy legislation in over a decade. One of the most significant provisions of EP Act empowers the Federal Energy Regulatory Commission (FERC) to certify an Electric Reliability Organization (ERO) to improve the reliability of the nation's "bulk power system" through mandatory and enforceable electric reliability standards (in contrast to the long-standing voluntary system). The definition of "bulk power system" does not include facilities used in the local distribution of electric energy. The ERO is to file any proposed reliability standard or modification with FERC. "Reliability standards" are a set of criteria and requirements relating to the reliable operation of the bulk-power system. Such a standard includes requirements for the operation of existing transmission facilities or the design of planned additions or modifications (to the extent necessary) to provide for reliable operation. It does not include, and the ERO may not impose, any requirement to enlarge existing or to construct new transmission or generation facilities. All users, owners, and operators of the bulk-power system are required to comply with the electric reliability standards. The ERO may impose a penalty on a user, owner, or operator for violating a reliability standard, and FERC may order compliance with such a standard and impose a penalty if it finds that a user, owner, or operator is about to engage in an act that would violate a reliability standard.

Based on the EP Act authority vested upon the FERC, the FERC approved the North American Electric Reliability Corporation (NERC) as the ERO. Currently, there are more than 100 mandatory NERC and Western Electricity Coordinating Council (WECC) reliability standards, all of which are subject to penalties ranging from $1,000 to $1,000,000, depending on the impact of the violation to reliability, and other factors. The Department has implemented a NERC/WECC Reliability Standards Compliance Program to proactively prevent, monitor, and stop potential violations to these standards.

The Department currently complies with the mandatory NERC/WECC Reliability Standards.

(b) Cybersecurity

Congress and the White House have been working to address the nation's cybersecurity concerns for a number of years. The last few years, the White House and the Senate Democrats have supported a comprehensive regulatory approach that defines critical infrastructure and regulates cybersecurity through the Department of Homeland Security. Senate Republicans have sought to address concerns through voluntary actions. Senate did not get the necessary support of 60 Senators to consider a comprehensive legislative approach twice in 2012.

The Department currently believes it complies with current cybersecurity NERC Reliability Standards.

(c) Final Rule on Transmission Planning and Cost Allocation – FERC Order No. 1000 (RM10-23-000)

On July 21, 2011, the FERC issued its order on transmission planning and cost allocation (Order 1000). On May 17, 2012, FERC issued Order 1000-A, stating that nonjurisdictional entities (such as LADWP) must formally enroll in a transmission planning region before it can be assessed costs under the regional cost allocation methodology. FERC also stated that nonjurisdictional entities must have a right to withdraw and avoiding cost allocations from the region.

However, Order 1000 and 1000A contain language that would significantly broaden FERC's authority to allocate transmission costs. FERC takes the unprecedented position that transmission costs may be allocated to entities in the absence of a contract or service relationship.

Most jurisdictional transmission providers filed their compliance filings to amend their tariffs to include a regional planning process in October 2012. FERC has recently issued orders with findings that many of the compliance filings in planning regions did not meet the requirements of Order 1000 with respect to cost allocation. LADWP as a nonjurisdictional entity was not required to make a filing.

The Final Rule urges, but does not require, government-owned utilities such as the Department and cooperative utilities to participate in regional transmission planning and cost allocation. FERC indicates that if "nonjurisdictional" transmission owners do not comply with Order No. 1000, they may not meet reciprocity requirements, and thus may have access to third-party transmission services limited.

(d) *Dodd-Frank Wall Street Reform and Consumer Protection Act*

On July 21, 2010, the "Dodd-Frank Wall Street Reform and Consumer Protection Act" (Dodd-Frank) was signed into law. Dodd-Frank was enacted to minimize systemic risk to the U.S. financial system, in part by establishing new rules related to swaps and other derivatives.

- First, Dodd-Frank generally requires that parties to swap transactions provide collateral for their swaps. This "margining" requirement means that a party to a swap must set aside cash or other collateral to secure its obligations under the swap.
- Second, Dodd-Frank generally requires that swap transactions be conducted or "cleared" through financial intermediaries. This clearing requirement means that parties generally cannot enter into a swap that is customized to the needs of the parties, as is typically the case for public power and other electric utilities. Dodd-Frank did, however, provide exceptions to both the margining and clearing requirements for "end users" that are using swaps to hedge commercial risks.
- Third, Dodd-Frank is to impose reporting requirements on swap transactions, including additional reporting for end-user transactions.
- Finally, Dodd-Frank imposed additional limitations on swaps with "special entities," including public power and other governmental entities, to ensure that these special entities are being properly advised and dealt with fairly in consummating swap transactions. These rules require that swap counterparty ensure that a special entity has an independent swap advisor and impose on the advisor a duty to act in the best interests of the special entity.

The CFTC has recently finalized a swap dealer definition exempting entities doing less than $3 billion ($8 billion during a transition period) in swaps from being regulated as a "swap dealer," and has further exempted transactions done between not-for-profit utilities from being considered swaps. The initial swap dealer definition also included a $25 million subthreshold over a 12-month period for entities doing business with "special entities".

Various organizations representing the "special entities" requested the CFTC to exclude government-owned utilities' swap transactions related to utility operations from counting toward the $25 million de minimis threshold, and rather be subjected to the overall $3 billion threshold. The CFTC considered the request for special entities and amended the rules to now be consistent with threshold definitions similar to investor owned utilities.

There is a proposed legislation (H.R.1038: Public Power Risk Management Act of 2013) that provides that the CFTC, in making a determination to exempt swap dealing activities below a de minimis threshold, cannot treat a utility operations-related swap with a utility special entity any differently than a utility operations-related swaps with an entity that is not a special entity.

The overall impact of these CFTC rulings on LADWP cannot be predicted at this time.

(4) Utility Plant

The Power System had the following activities in utility plant during fiscal year 2014 (amounts in thousands):

		Balance June 30, 2013	Additions	Retirements and disposals	Transfers	Balance June 30, 2014
Nondepreciable utility plant:						
Land and land rights	$	197,405	44	(345)	—	197,104
Construction work in progress		884,378	622,824	—	(271,257)	1,235,945
Nuclear fuel		44,686	12,179	(13,934)	—	42,931
Natural gas field		272,158	330	(23,565)	—	248,923
Total nondepreciable utility plant		1,398,627	635,377	(37,844)	(271,257)	1,724,903
Depreciable utility plant:						
Generation		5,089,796	59,903	(3,401)	99,061	5,245,359
Transmission		1,009,771	13,829	(157)	(8,079)	1,015,364
Distribution		6,616,751	297,675	(219)	74,938	6,989,145
General		1,359,434	76,771	(5,674)	105,337	1,535,868
Total depreciable utility plant		14,075,752	448,178	(9,451)	271,257	14,785,736
Accumulated depreciation:						
Generation		(2,711,487)	(145,442)	3,401	—	(2,853,528)
Transmission		(416,441)	(27,708)	157	—	(443,992)
Distribution		(2,908,894)	(230,491)	219	—	(3,139,166)
General		(816,767)	(50,263)	5,674	—	(861,356)
Total accumulated depreciation		(6,853,589)	(453,904)	9,451	—	(7,298,042)
Total utility plant, net	$	8,620,790	629,651	(37,844)	—	9,212,597

Depreciation and amortization expense during fiscal year 2014 was $466.5 million.

The Power System had the following activities in utility plant during fiscal year 2013 (amounts in thousands):

	Balance June 30, 2012	Additions	Retirements and disposals	Transfers	Balance June 30, 2013
Nondepreciable utility plant:					
Land and land rights	$ 166,137	31,390	(122)	—	197,405
Construction work in progress	1,211,851	508,405	—	(835,878)	884,378
Nuclear fuel	49,687	8,858	(13,859)	—	44,686
Natural gas field	293,006	5,328	(26,176)	—	272,158
Total nondepreciable utility plant	1,720,681	553,981	(40,157)	(835,878)	1,398,627
Depreciable utility plant:					
Generation	4,281,370	62,858	(2,383)	747,951	5,089,796
Transmission	967,068	2,817	—	39,886	1,009,771
Distribution	6,295,169	279,055	(96)	42,623	6,616,751
General	1,312,291	58,090	(16,365)	5,418	1,359,434
Total depreciable utility plant	12,855,898	402,820	(18,844)	835,878	14,075,752
Accumulated depreciation:					
Generation	(2,595,719)	(118,151)	2,383	—	(2,711,487)
Transmission	(389,938)	(26,503)	—	—	(416,441)
Distribution	(2,691,780)	(217,210)	96	—	(2,908,894)
General	(785,478)	(47,654)	16,365	—	(816,767)
Total accumulated depreciation	(6,462,915)	(409,518)	18,844	—	(6,853,589)
Total utility plant, net	$ 8,113,664	547,283	(40,157)	—	8,620,790

Depreciation and amortization expense during fiscal year 2013 was $418.5 million.

(5) Jointly Owned Utility Plant

The Power System has direct interests in several electric generating stations and transmission systems, which are jointly owned with other utilities. As of June 30, 2014 and 2013, utility plant includes the following amounts related to the Power System's ownership interest in each jointly owned utility plant (dollar amounts in thousands):

	Ownership interest	Share of capacity (MWs)	Utility plant in service June 30, 2014 Cost	Utility plant in service June 30, 2014 Accumulated depreciation	Utility plant in service June 30, 2013 Cost	Utility plant in service June 30, 2013 Accumulated depreciation
Palo Verde Nuclear Generating Station	5.7%	224	$ 623,893	403,329	615,703	389,158
Navajo Generating Station	21.2	477	349,781	320,216	348,099	317,782
Mohave Generating Station	10.0	—	65,550	57,852	65,317	57,852
Pacific Intertie DC Transmission Line	40.0	1,240	183,253	63,072	182,091	58,636
Other transmission systems	—	Various	96,144	57,571	90,384	54,774
			$ 1,318,621	902,040	1,301,594	878,202

The Power System will incur certain minimal operating costs related to the jointly owned facilities, regardless of the amount or its ability to take delivery of its share of energy generated. The Power System's proportionate share of the operating costs of the joint plants is included in the corresponding categories of operating expenses.

(6) Purchase Power Commitments

As of June 30, 2014, the Power System has entered into a number of energy and transmission service contracts, which involve substantial commitments as follows (dollar amounts in thousands):

	Agency	Agency share	The Power System's interest in agency's share Interest	The Power System's interest in agency's share Capacity (MWs)	The Power System's interest in agency's share Outstanding principal
Intermountain Power Project	IPA	100.0%	69.1%	1,244	$ 922,144
Palo Verde Nuclear Generating Station	SCPPA	5.9	67.0	151	31,798
Mead-Adelanto Project	SCPPA	68.0	35.7	313	45,043
Mead-Phoenix Project	SCPPA	17.8–22.4	24.8	148	9,521
Southern Transmission System	SCPPA	100.0	59.5	1,429	421,566
Milford I Wind	SCPPA	100.0	92.5	188	197,622
Windy Point	SCPPA	100.0	92.4	262*	467,171
Linden Wind Energy	SCPPA	100.0	90.0	50*	129,030
Milford II Wind	SCPPA	100.0	95.1	102*	148,165
Apex Power Project	SCPPA	100.0	100	531	318,860

* Power System will receive 100%, unless City of Glendale exercises its option to repurchase any of its contract output entitlement share.

IPA – The Intermountain Power Agency (IPA) is an agency of the State of Utah established to own, acquire, construct, operate, maintain, and repair the Intermountain Power Project (IPP). The Power System serves as the project manager and operating agent of IPP.

SCPPA – The Southern California Public Power Authority is a California Joint Powers Agency that finances the construction or acquisition of generation, transmission, and renewable energy projects.

The above agreements require the Power System to make certain minimum payments, which are based primarily upon debt service requirements. In addition to average annual fixed charges of approximately $300 million during each of the next five years, the Power System is required to pay for operating and maintenance costs related to actual deliveries of energy under these agreements (averaging approximately $613 million annually during each of the next five years). The Power System made total payments under these agreements of approximately $827 million and $782 million in fiscal years 2014 and 2013, respectively. These agreements are scheduled to expire from 2027 to 2040.

The Power System earned fees under the IPP project manager and operating agent agreements totaling $24.1 million and $23.8 million in fiscal years 2014 and 2013, respectively.

(a) Long-Term Notes Receivable

Under the terms of its purchase power agreement with IPA, the Department is charged for its output entitlements based on its share of IPA's costs, including debt service. During fiscal year 2000, the Department restructured a portion of this obligation by transferring $1.11 billion to IPA in exchange for long-term notes receivable. The funds transferred were obtained from the debt reduction trust funds and through the issuance of new variable rate debentures (see notes 7 and 10). IPA used the proceeds from these transactions to defease and to tender bonds with par values of approximately $618 million and $611 million, respectively.

On September 7, 2000, the Department paid $187 million to IPA in exchange for additional long-term notes receivable. IPA used the proceeds to defease bonds with a face value of $198 million.

On July 20, 2005, the Department paid $97 million to IPA in exchange for additional long-term notes receivable. IPA used the proceeds to defease bonds with a face value of $92 million.

The IPA notes are subordinate to all of IPA's publicly held debt obligations. The Power System's future payments to IPA will be partially offset by interest payments and principal maturities from the subordinated notes receivable. The net IPA notes receivable balance totaled $773 million and $844 million as of June 30, 2014 and 2013, respectively.

The IPA notes pay interest and principal monthly and mature on July 1, 2023. The interest rates range from 1.7% to 5.9%, subject to adjustments related to IPA bond refundings.

(b) Energy Entitlement

The Department has a contract through 2017 with the U.S. Department of Energy for the purchase of available energy generated at the Hoover Power Plant. The Department's contractual share of contingent capacity at Hoover is 491 MW (maximum rated capability). The cost of power (approximately 455 MW of capacity and 599,000 MWH of energy) purchased under this contract, including the Lower Colorado River Basin Development Fund Contribution Charge, was approximately $17.3 million and $21 million as of June 30, 2014 and 2013, respectively.

On December 20, 2011, the President signed H.R. 470, the "Hoover Power Allocation Act of 2011," into law. The legislation reallocates, for 50 more years, power from the Hoover Dam Power Plant to existing contractors while creating an additional pool of 5% power for new entrants.

The Department has a contract through 2026 with SCPPA for the purchase of available energy generated at the Pebble Springs Wind Project located in Gilliam County, Oregon. The Power System's share of capacity at Pebble Springs is approximately 69 MWs (maximum capacity). The cost of power purchased under this contract was $18.5 million and $16.5 million as of June 30, 2014 and 2013, respectively.

(c) Electricity Swap and Forward Contracts

In order to obtain the highest market value on energy that is sold into the wholesale market, the Department monitors the sales price of energy, which varies based on which hub the energy is to be delivered. There are three primary hubs within the Department's transmission region: Palo Verde, California Oregon Border, and Mead. The Department enters into various locational swap transactions with other electric utilities in order to effectively utilize its transmission capacity and to achieve the most economical exchange of energy purchased and sold.

The Department procures renewable energy resources located remotely. These resources provide intermittent and limited source of energy and these resources are not directly connected to the Department's transmission system. In order to receive firm renewable energy, the Department entered into a green-for-green energy exchange with the same or different Renewable Energy Credit source.

The Department enters into power and natural gas forward contracts in order to meet the electricity requirements to serve its customers. To assist the Department in achieving its Renewable Portfolio Standards (RPS) goal of 20%, some of the forward purchases made are renewable energy and biomethane gas.

The Department does not enter into swap and forward transactions for trading purposes. All of these transactions are intended to be used in the Department's normal course of operations. The Department is exposed to risk of nonperformance if the counterparties default or if the swap agreements are terminated.

As of June 30, 2014, the Power System had the following Electricity Swap and Forward Contracts, which are not recorded in the Power System's financial statements based on the criteria in GASB Statement No. 53 (amounts in thousands):

Description	Notional amount (total contract quantities)	Contract price range dollar per unit	First effective date	Last termination date	Fair value	Cash paid at inception
Electricity swaps:						
Purchases	284,960 MW	$ 42.50–51.50	07/01/14	12/31/14	$ (12,291)	—
Sales	284,960 MW	45.00–55.00	07/01/14	12/31/14	13,023	—
Forward contracts:						
Electricity	676,157 MW	38.35–65.00	07/01/14	06/30/14	1,731	—
Natural gas	35,973,600 MMBtu	4.33–10.85	07/01/14	10/31/21	(162,738)	—

As of June 30, 2013, the Power System had the following Electricity Swap and Forward Contracts, which are not recorded in the Power System's financial statements based on the criteria in GASB Statement No. 53 (amounts in thousands):

Description	Notional amount (total contract quantities)	Contract price range dollar per unit	First effective date	Last termination date	Fair value	Cash paid at inception
Electricity swaps:						
Purchases	353,280 MW	$ 35.82–38.83	07/01/13	12/31/13	$ (12,991)	—
Sales	353,280 MW	38.32–41.33	07/01/13	12/31/13	13,874	—
Forward contracts:						
Electricity	555,980 MW	26.50–53.65	07/01/13	06/30/14	(3,940)	—
Natural gas	37,655,600 MMBtu	5.49–10.85	07/01/13	10/31/21	(218,672)	—

(7) Cash, Cash Equivalents, and Investments

(a) Restricted and Other Investments

A summary of the Power System's restricted and other investments is as follows (amounts in thousands):

	June 30 2014	June 30 2013
Restricted and other investments:		
Restricted investments:		
Debt Reduction Trust Funds	$ 496,841	490,325
Nuclear Decommissioning Trust Funds	126,521	122,584
Natural Gas Trust Fund	292	287
Hazardous Waste Treatment Trust Fund	2,204	2,182
SCPPA Palo Verde investment	14,236	18,525
Total restricted investments	$ 640,094	633,903

The Power System also has $1.4 million and $3.2 million of cash collateral received from securities lending transactions in the City's securities lending program as of June 30, 2014 and 2013, respectively (see notes 7(b) and 8).

All restricted and other investments are to be used for a specific purpose as follows:

Debt Reduction Trust Funds

The debt reduction trust funds were established during fiscal year 1997 to provide for the payment of principal and interest on long-term debt obligations and purchased power obligations arising from the Department's participation in IPP and SCPPA (see note 6). The Department has transferred funds from purchased power precollections into these trust funds. Funds from operations may also be transferred by management as funds become available.

Nuclear Decommissioning Trust Funds

Nuclear decommissioning trust funds will be used to pay the Department's share of decommissioning PVNGS at the end of its useful life (see note 1).

Natural Gas Trust Fund

The natural gas trust fund was established to serve as depository to pay for costs and to post margin or collateral in connection with contracts for the purchase and delivery of financial transactions for natural gas. These transactions are entered into to stabilize the natural gas portion of the Department's fuel for generation costs.

Hazardous Waste Treatment Storage and Disposal Trust Fund

The hazardous waste treatment storage and disposal trust fund was established to provide financial assurance for closure of the Main Street treatment and disposal facility.

SCPPA Palo Verde Investment

The SCPPA Palo Verde investment is a fixed rate investment held by SCPPA to be drawn down over the next three years to pay for purchased power obligations arising from the Department's participation in the SCPPA Palo Verde project. The fixed interest rate is 4.97% and the maturity date is June 25, 2017.

As of June 30, 2014, the Power System's restricted investments and their maturities are as follows (amounts in thousands):

		Investment maturities				
Investment type	Fair value	1 to 30 days	31 to 60 days	61 to 365 days	366 days to 5 years	Over 5 years
U.S. government securities	$ 5,001	—	—	—	5,001	—
U.S. agencies	322,519	—	—	55,966	209,977	56,576
Medium-term corporate notes	113,687	262	—	31,990	81,435	—
Commercial paper	54,748	49,749	4,999	—	—	—
Certificates of deposit	11,001	1,000	—	10,001	—	—
California local agency bonds	28,901	—	8,189	3,635	17,077	—
California state bonds	17,636	—	—	3,478	14,158	—
Other state bonds	55,487	—	596	6,004	48,887	—
Bankers' acceptances	260	—	260	—	—	—
Money market funds	16,618	16,618	—	—	—	—
SCPPA Palo Verde investment	14,236	—	—	—	14,236	—
	$ 640,094	67,629	14,044	111,074	390,771	56,576

As of June 30, 2013, the Power System's restricted investments and their maturities are as follows (amounts in thousands):

		Investment maturities				
Investment type	Fair value	1 to 30 days	31 to 60 days	61 to 365 days	366 days to 5 years	Over 5 years
U.S. agencies	$ 267,575	—	—	25,136	182,121	60,318
Medium-term corporate notes	154,635	377	1,000	49,778	103,480	—
Commercial paper	64,737	34,748	19,998	9,991	—	—
Certificates of deposit	16,000	6,000	5,000	5,000	—	—
California local agency bonds	45,331	—	—	24,807	20,524	—
California state bonds	18,215	—	—	5,175	13,040	—
Other state bonds	38,639	—	—	440	38,199	—
Bankers' acceptances	250	—	—	250	—	—
Money market funds	9,996	9,996	—	—	—	—
SCPPA Palo Verde investment	18,525	—	—	—	18,525	—
	$ 633,903	51,121	25,998	120,577	375,889	60,318

i. Interest Rate Risk

The Department's investment policy limits the maturity of its investments to a maximum of 30 years for U.S. government agency securities; 5 years for medium-term corporate notes, California local agency obligations, California state obligations, and other state obligations; 270 days for commercial paper; 397 days for certificates of deposit; 180 days for bankers' acceptances; and 45 days for repurchase agreements purchased with cash collateral from securities lending agreements.

ii. Credit Risk

Under its investment policy and the Code, the Department is subject to the prudent investor standard of care in managing all aspects of its portfolios. The prudent investor standard requires that the Department "shall act with care, skill, prudence, and diligence under the circumstances then prevailing, including, but not limited to, the general economic conditions and the anticipated needs of the agency, that a prudent person acting in a like capacity and in familiarity with those matters would use in the conduct of funds of a like character and with like aims, to safeguard the principal and maintain the liquidity needs of the agency."

The U.S. government agency securities in the portfolio consist of securities issued by government-sponsored enterprises, which are not explicitly guaranteed by the U.S. government. Of the U.S. government agency securities in the portfolio as of June 30, 2014, $315,164,889 (98%) was rated with either the highest or second highest possible credit ratings by the Nationally Recognized Statistical Rating Organizations (NRSROs) that rated them and $7,353,673 (2%) was not rated. Of the U.S. government agency securities in the portfolio as of June 30, 2013, $260,358,151 (97%) was rated with either the highest or second highest possible credit ratings by the Nationally Recognized Statistical Rating Organizations (NRSROs) that rated them and $7,216,510 (3%) was not rated.

The Department's investment policy specifies that medium-term corporate notes must be rated in a rating category of "A" or its equivalent or better by a NRSRO. Of the Power System's investments in corporate notes as of June 30, 2014, $3,014,835 (3%) was rated in the category of AAA, $63,948,291 (56%) was rated in the category of AA, and $46,462,252 (41%) was rated in the category of A by at least one NRSRO. The remaining $261,455 (less than 1%) of investments in corporate notes was not rated. Of the Power System's investments in corporate notes as of June 30, 2013, $8,060,781 (5%) was rated in the category of AAA, $75,473,574 (49%) was rated in the category of AA, and $70,724,196 (46%) was rated in the category of A by at least one NRSRO. The remaining $376,598 (less than 1%) of investments in corporate notes was not rated.

The Department's investment policy specifies that commercial paper must be of the highest ranking or of the highest letter and number rating as provided for by at least two NRSROs. As of June 30, 2014 and 2013, all of the Power System's investments in commercial paper were rated with at least the highest letter and number rating as provided by at least two NRSROs.

The Department's investment policy specifies that negotiable certificates of deposit must be of the highest ranking or letter and number rating as provided for by at least two NRSROs and that for nonnegotiable certificates of deposit, the full amount of principal and interest is insured by the Federal Deposit Insurance Corporation (FDIC) or National Credit Union Administration. As of June 30, 2014, the Power System's investments in certificates of deposits included $10,000,550 of negotiable certificates of deposit with at least the highest letter and number rating as provided by at least two NRSROs and $1,000,000 of nonnegotiable certificates of deposit fully insured by the FDIC. As of June 30, 2013, the Power System's investments in certificates of deposits included $15,000,980 of negotiable certificates of deposit with at least the highest letter and number rating as provided by at least two NRSROs and $1,000,000 of nonnegotiable certificates of deposit fully insured by the FDIC.

The Department's investment policy specifies that California local agency obligations, which include municipal commercial paper, must be rated in a rating category of "A" or its equivalent or better by a NRSRO. Of the Power System's investments in California local agency bonds as of June 30, 2014, $25,842,130 (89%) was rated in the category of AA; $2,060,050 (7%) was rated in the category of A; and $999,260 (3%) was rated with the highest short-term letter and number rating as provided by at least one NRSRO (Note: Percentages do not add up to 100% due to rounding. Of the Power System's investments in California local agency bonds as of June 30, 2013, $26,055,858 (57%) was rated in the category of AA; $3,990,207 (9%) was rated in the category of A; and $15,284,920 (34%) was rated with the highest short-term letter and number rating as provided by at least one NRSRO.

The Department's investment policy specifies that State of California obligations must be rated in a rating category of "A" or its equivalent or better by a NRSRO. Of the Power System's investments in State of California Obligations as of June 30, 2014, $3,643,456 (21%) was rated in the category of AAA and $13,992,573 (79%) was rated in the category of AA by at least one NRSRO. Of the Power System's investments in State of California Obligations as of June 30, 2013, $3,637,577 (20%) was rated in the category of AAA, $1,469,460 (8%) was rated in the category of AA, and $13,107,568 (72%) was rated in the category of A by at least one NRSRO.

The Department's investment policy specifies that obligations of other states in addition to California must be rated in a rating category of "A" or its equivalent or better by a NRSRO. Of the Power System's investments in other state obligations as of June 30, 2014, $21,963,990 (39%) was rated in the category of AAA, $32,522,446 (59%) was rated in the category of AA, and $1,000,520 (2%) was rated in the category of A by at least one NRSRO. Of the Power System's investments in other state obligations as of June 30, 2013, $15,933,055 (41%) was rated in the category of AAA and $22,706,260 (59%) was rated in the category of AA by at least one NRSRO.

The Department's investment policy specifies that banker's acceptances must be of the highest ranking or letter and number rating as provided for by at least two NRSROs. As of June 30, 2014 and 2013, all of the Power System's investments in banker's acceptances were rated with at least the highest letter and number rating as provided by three NRSROs.

The Department's investment policy specifies that money market funds may be purchased as allowed under the Code, which requires that the fund must have either (1) attained the highest ranking or highest letter and numerical rating provided by not less than two NRSROs or (2) retained an investment advisor registered or exempt from registration with the Securities and Exchange Commission with not less than five years experience in managing money market mutual funds with assets under management in excess of $500 million. As of June 30, 2014 and 2013, each of the money market funds in the portfolio had the highest possible ratings by at least two NRSROs.

(Continued)

iii. Concentration of Credit Risk

The Department's investment policy specifies that there is no percentage limitation on the amount that can be invested in U.S. government agency securities, except that a maximum of 30% of the cost value of the portfolio may be invested in the securities of any single U.S. government agency issuer.

Of the Power System's total investments as of June 30, 2014, $105,810,853 (17%) was invested in securities issued by the Federal Home Loan Mortgage Corporation; $98,248,817 (15%) was invested in securities issued by the Federal Home Loan Bank; and $97,438,516 (15%) was invested in securities issued by the Federal National Mortgage Association.

Of the Power System's total investments as of June 30, 2013, $130,545,599 (21%) was invested in securities issued by the Federal National Mortgage Association; $85,643,771 (14%) was invested in securities issued by the Federal Home Loan Mortgage Corporation; and $38,070,812 (6%) was invested in securities issued by the Federal Home Loan Bank.

(b) Pooled Investments

The Power System's cash, cash equivalents, and its collateral value of the City's securities lending program (SLP) are included within the City Treasury's general and special investment pool (the Pool). As of June 30, 2014 and 2013, the Power System's share of the City's general and special investment pool was $1,385,082 and $1,463,242,000, which represents approximately 15.9% and 17.3% of the Pool, respectively.

The cash balances of substantially all funds on deposit in the City Treasury are pooled and invested by the City Treasurer for the purpose of maximizing interest earnings through pooled investment activities but safety and liquidity still take precedence over return. Interest earned on pooled investments is allocated to the participating funds based on each fund's average daily deposit balance during the allocation period with all remaining interest allocated to the General Fund. Investments in the City Treasury are stated at fair value based on quoted market prices except for commercial paper and money market investments that have remaining maturities of one year or less at time of purchase, which are reported at amortized cost.

Pursuant to California Government Code Section 53607 and the Los Angeles City Council File No. 94-2160, the City Treasury shall render to the City Council a statement of investment policy (the Policy) annually. City Council File No. 09-3050 was adopted on January 27, 2010 as the City's investment policy. This Policy shall remain in effect until the Los Angeles City Council and the Mayor approve a subsequent revision. The Policy governs the City's pooled investment practices. The Policy addresses soundness of financial institutions in which the City Treasurer will deposit funds and types of investment instruments permitted by California Government Code Sections 53600-53635 and 16429.1.

Examples of investments permitted by the Policy are obligations of the U.S. Treasury and government agencies, commercial paper notes, certificates of deposit (CD) placement service, bankers' acceptances, medium-term notes, mutual funds, money market mutual funds, and the State of California Local Agency Investment Fund.

At June 30, 2014, the investments held in the City Treasury's General and Special Investment Pool Programs and their maturities are as follows (in thousands):

		Investment maturities				
Type of investments	Amount	1 to 30 days	31 to 60 days	61 to 365 days	366 days to 5 years	Over 5 years
U.S. Treasury bills	$ 248,766	248,746	—	20	—	—
U.S. Treasury notes	4,121,579	—	—	—	4,085,830	35,749
U.S.-Sponsored Agency Issues	1,915,548	606,056	213,475	352,807	730,202	13,008
Medium term notes	1,443,640	—	—	191,976	1,231,654	20,010
Commercial paper	904,407	867,252	26,998	10,157	—	—
Municipal bonds	30,207	—	—	—	30,207	—
Certificates of deposit	7,000	—	—	7,000	—	—
Short-term investment funds	5,609	5,609	—	—	—	—
Securities lending short-term collateral investment pool	11,425	11,425	—	—	—	—
Total general and special pools	$ 8,688,181	1,739,088	240,473	561,960	6,077,893	68,767

Interest Rate Risk: The Policy limits the maturity of its investments to five years for the U.S. Treasury and government agency securities, medium term notes, CD placement service, negotiable certificate of deposits, collateralized bank deposits, mortgage pass-through securities, and bank/time deposits; one year for repurchase agreements; 270 days for commercial paper; 180 days for bankers' acceptances; and 92 days for reverse repurchase agreements. The Policy also allows City funds with longer-term investments horizons, to be invested in securities that at the time of the investment have a term remaining to maturity in excess of five years, but with a maximum final maturity of thirty years.

Credit Risk: The Policy establishes minimum credit ratings requirement for investments. There is no credit quality requirement for local agency bonds, U.S. Treasury Obligations, State of California Obligations, California Local Agency Obligations, and U.S.-Sponsored Agencies (U.S. government sponsored enterprises) securities. The City's $1.9 billion investments in U.S. government-sponsored enterprises consist of securities issued by the Federal Home Loan Bank – $896.7 million, Federal National Mortgage Association – $675.8 million, Federal Home Loan Mortgage Corporation – $279.7 million, Federal Farm Credit Bank – $17.3 million, and Tennessee Valley Authority – $46.2 million. Of the City's $1.9 billion investments in U.S.-Sponsored Agencies securities, $798.3 million were rated "AA+" by S&P and "Aaa" by Moody's; $1,117.3 million were not rated individually by S&P nor Moody's (issuers of these securities are rated "AA+/A-1+" by S&P and "Aaa/P-1" by Moody's).

Medium term notes must be issued by corporations organized and operating within the United States or by depository institutions licensed by the United States or any state and operating within the United States. Medium term notes must have at least an "A" rating. The City's $1.4 billion investments in medium term notes consist of securities issued by banks and corporations that comply with these requirements and were rated "A" or better by S&P and "A3" or better by Moody's. Subsequent to purchase, two issuers of $38.7 million medium term notes were downgraded to "A-1" by S&P and "Baa1" by Moody's and one issuer of $7.0 million medium term notes was downgraded to "BBB+" by S&P and "A3" by Moody's.

Commercial paper issues must have a minimum of "A-1" or equivalent rating. If the issuer has issued long-term debt, it must be rated "A" without regard to modifiers. Issuing corporation must be organized and operating within the United States and have assets in excess of $500.0 million. The City's $904.4 million investments in commercial paper were rated "A-1+/A-1" by S&P and "P-1" by Moody's.

Municipal bonds have no minimum rating requirement. The City's $30.2 million investments in municipal bonds were rated "AA/A" by S&P and "Aa2/Aa3" by Moody's.

The issuers of the certificates of deposit were not rated.

Concentration of Credit Risk: The Policy does not allow more than 40% of its investment portfolio be invested in commercial paper and bankers' acceptances, 30% in certificates of deposit and medium term notes, 20% in mutual funds, money market mutual funds, and mortgage pass-through securities. The Policy further provides for a maximum concentration limit of 10% in any one issuer including its related entities. There is no percentage limitation on the amount that can be invested in the U.S. government agencies. The City's pooled investments comply with these requirements. GAAP requires disclosure of certain investments in any one issuer that represent 5% or more of total investments. Of the City's total pooled investments as of June 30, 2014, $896.7 million (10%) was invested in securities issued by Federal Home Loan Bank, and $675.8 million (8%) was invested in securities issued by Federal National Mortgage Association.

At June 30, 2013, the investments held in the City Treasury's General and Special Investment Pool Programs and their maturities are as follows (amounts in thousands):

Type of investments	Amount	Investment maturities 1 to 30 days	31 to 60 days	61 to 365 days	366 days to 5 years	Over 5 years
U.S. Treasury bills	$ 184,540	20,999	—	163,541	—	—
U.S. Treasury notes	3,705,030	—	—	—	3,687,736	17,294
U.S.-Sponsored Agency Issues	1,980,334	153,076	240,942	512,318	1,060,252	13,746
Medium term notes	1,467,556	8,913	32,361	201,292	1,224,990	—
Commercial paper	1,071,321	962,231	33,999	75,091	—	—
Municipal bonds	9,774	—	—	—	9,774	—
Certificates of deposit	7,000	—	—	7,000	—	—
Short-term investment funds	22,261	22,261	—	—	—	—
Securities lending short-term collateral investment pool	31,659	31,659	—	—	—	—
Total general and special pools	$ 8,479,475	1,199,139	307,302	959,242	5,982,752	31,040

Interest Rate Risk: The Policy limits the maturity of its investments to five years for the U.S. Treasury and government agency securities, medium term notes, CD placement service, negotiable certificate of deposits, collateralized bank deposits, mortgage pass-through securities, and bank/time deposits; one year for repurchase agreements; 270 days for commercial paper; 180 days for bankers' acceptances; and 92 days for reverse repurchase agreements. The Policy also allows City funds with longer-term investments horizons, to be invested in securities that at the time of the investment have a term remaining to maturity in excess of five years, but with a maximum final maturity of thirty years.

Credit Risk: The Policy establishes minimum credit ratings requirement for investments. There is no credit quality requirement for local agency bonds, U.S. Treasury Obligations, State of California Obligations, California Local Agency Obligations, and U.S.-Sponsored Agencies (U.S. government-sponsored enterprises) securities. The City's $2.0 billion investments in U.S. government-sponsored enterprises consist of securities issued by the Federal Home Loan Bank – $292.5 million, Federal National Mortgage Association – $880.9 million, Federal Home Loan Mortgage Corporation – $617.1 million, Federal Farm Credit Bank – $121.7 million, Tennessee Valley Authority – $62.0 million and Farmer Mac Discount Note – $6.1 million. Of the City's $2.0 billion investments in U.S.-Sponsored Agencies securities, $1,281.6 million were rated "AA+" by S&P and "Aaa" by Moody's; $698.7 million were not rated individually by S&P nor Moody's (issuers of these securities are rated "A-1+" by S&P and "P-1" by Moody's).

Medium term notes must be issued by corporations organized and operating within the United States or by depository institutions licensed by the United States or any state and operating within the United States. Medium term notes must have at least an "A" rating. The City's $1.5 billion investments in medium term notes consist of securities issued by banks and corporations that comply with these requirements and were rated "A" or better by S&P and "A3" or better by Moody's. Subsequent to purchase, one issuer of $12.0 million medium term notes was downgraded to "BBB" by S&P and Baa1 by Moody's.

Commercial paper issues must have a minimum of "A-1" or equivalent rating. If the issuer has issued long-term debt, it must be rated "A" without regard to modifiers. Issuing corporation must be organized and operating within the United States and have assets in excess of $500.0 million. Of the City's $1.1 billion investments in commercial paper, $971.0 million were rated A-1 +/A-1 by S&P and P-1 by Moody's; $33.0 million were rated P-1 by Moody's and not rated by S&P; $67.3 million were not rated individually by S&P nor Moody's. The issuers of the certificates of deposit and municipal bonds were not rated.

Concentration of Credit Risk: The Policy does not allow more than 40% of its investment portfolio be invested in commercial paper and bankers' acceptances, 30% in certificates of deposit and medium term notes, and 20% in mutual funds, money market mutual funds, and mortgage pass-through securities. The Policy further provides for a maximum concentration limit of 10% in any one issuer of commercial paper as well as in any one mutual fund, and 30% in bankers' acceptances of any one commercial bank. There is no percentage limitation on the amount that can be invested in the U.S. government agencies. The City's pooled investments comply with these requirements. GAAP requires disclosure of certain investments in any one issuer that represent 5%

or more of total investments. Of the City's total pooled investments as of June 30, 2013, $617.1 million (7%) was invested in securities issued by Federal Home Loan Mortgage Corporation, and $880.9 million (10%) was invested in securities issued by Federal National Mortgage Association.

(8) Securities Lending Transactions

The Power System participates in an SLP. As of June 30, 2014 and 2013, amounts held in the City of Los Angeles Program are as follows (collateral amounts in thousands):

Program		June 30 2014	June 30 2013
City of Los Angeles Program	$	1,419	3,164

General Investment Pool Program

The Power System participates in the City's SLP through the pooled investment fund. The Department recognizes its proportionate share of the cash collateral received for securities loaned and the related obligation for the general investment pool. Securities lending is permitted and limited under provisions of California Government Code Section 53601. The City Council approved the SLP on October 22, 1991 under Council File No. 91-1860, which complies with the California Government Code. The objectives of the SLP in priority order are safety of loaned securities and prudent investment of cash collateral to enhance revenue from the investment program. The SLP is governed by a separate policy and guidelines.

The City's custodial bank acts as the securities lending agent. In the event a counterparty defaults by reason of an act of insolvency, the bank shall take all actions which it deems necessary or appropriate to liquidate permitted investment and collateral in connection with such transaction and shall make a reasonable effort for two business days (Replacement Period) to apply the proceeds thereof to the purchase of securities identical to the loaned securities not returned. If during the Replacement Period the collateral liquidation proceeds are insufficient to replace any of the loaned securities not returned, the bank shall, subject to payment by the City of the amount of any losses on any permitted investments, pay such additional amounts as necessary to make such replacement.

Under the provisions of the SLP, and in accordance with the California Government Code, no more than 20% of the market value of the General Investment Pool (the Pool) is available for lending. The City receives cash as collateral on loaned securities, which is reinvested in securities permitted under the Policy. In addition, the City receives securities as collateral on loaned securities, which the City has no ability to pledge or sell without borrower default. In accordance with the California Government Code, the securities lending agent marks to market the value of both the collateral and the reinvestments daily. Except for open loans where either party can terminate a lending contract on demand, term loans have a maximum life of 60 days. Earnings from securities lending accrue to the Pool and are allocated on a pro rata basis to all Pool participants.

During the fiscal year 2014, collateralizations on all loaned securities were compliant with the required 102% of the market value. The City can sell collateral securities only in the event of borrower default. The lending agent provides indemnification for borrower default. There were no violations of legal or contractual provisions and no borrower or lending agent default losses during the fiscal year. There was no credit risk exposure to the City because the amounts owed to the borrowers exceeded the amounts borrowed. Loaned securities are held by the City's agents in the City's name and are not subject to custodial credit risk.

(9) Derivative Instruments

In June 2008, GASB issued GASB Statement No. 53. The statement specifically requires governments to measure and report most derivative instruments at fair value in their financial statements that are prepared using the economic resources measurement focus and the accrual basis of accounting. The requirement of reporting the derivative instruments at fair value on the face of the basic financial statements gives the users of those statements a clearer look into the risks their governments are sometimes exposed to when they enter into these transactions and how those risks are managed. The statement also addresses hedge accounting requirements and improves disclosures, providing a summary of the government's derivative instrument activity, its objectives for entering into derivative instruments, and its significant terms and risks. The Power System implemented GASB Statement No. 53 in the 2010 fiscal year.

In accordance with GASB Statement No. 53, the Power System records the fair value of its hedging derivative instruments, financial natural gas hedges, on the statement of net position. As of June 30, 2014 and 2013, the fair values of the financial natural gas hedges were approximately \$(48.5) million and approximately \$(67.3) million, respectively.

(a) Financial Natural Gas Hedges

The Department enters into natural gas hedging contracts in order to stabilize the cost of gas needed to produce electricity to serve its customers. It is designed to cap gas prices over a portion of the forecasted gas requirements.

The Department does not speculate when entering into financial transactions. Financial hedges are variable to fixed rate swaps and are layered by volumetric averaging. The Department is exposed to financial settlement risk if the counterparties default and/or the agreements are terminated.

As of June 30, 2014, the Power System's financial natural gas hedges by fiscal year are the following (amounts in thousands):

Derivative description	Notional amount (Total contract quantities*)	Contract price range dollar per unit	First effective date	Last termination date	Fair value	Cash paid at derivative inception
Financial natural gas:						
FY 2014-15	$ 5,384,500	6.37–9.38	07/01/14	06/30/15	$ (16,366)	—
FY 2015-16	4,488,000	6.42–9.85	07/01/15	06/30/16	(15,647)	—
FY 2016-17	3,197,500	6.61–9.83	07/01/16	06/30/17	(10,831)	—
FY 2017-18	2,190,000	6.76–7.14	07/01/17	06/30/18	(5,673)	—
Total	$ 15,260,000	6.37–9.85	07/01/13	06/30/18	$ (48,517)	—

* Contract quantities in MMBtu – Million British Thermal Units

As of June 30, 2013, the Power System's financial natural gas hedges by fiscal year are the following (amounts in thousands):

Derivative description	Notional amount (Total contract quantities*)	Contract price range dollar per unit	First effective date	Last termination date	Fair value	Cash paid at derivative inception
Financial natural gas:						
FY 2013-14	$ 5,027,000	6.37–8.31	07/01/13	06/30/14	$ (17,750)	—
FY 2014-15	5,384,500	6.37–9.38	07/01/14	06/30/15	(18,834)	—
FY 2015-16	4,488,000	6.42–9.85	07/01/15	06/30/16	(15,447)	—
FY 2016-17	3,197,500	6.61–9.83	07/01/16	06/30/17	(10,203)	—
FY 2017-18	2,190,000	6.76–7.14	07/01/17	06/30/18	(5,041)	—
Total	$ 20,287,000	6.37–9.85	07/01/13	06/30/18	$ (67,275)	—

* Contract quantities in MMBtu – Million British Thermal Units

The fair value of the natural gas hedges increased by $18.8 million and is reported as a liability and is offset by a deferred outflow on the statement of net position. All fair values were estimated using forward market prices available from broker quotes and exchanges.

(b) Credit Risk

The Power System is exposed to credit risk related to nonperformance by its wholesale counterparties under the terms of contractual agreements. In order to limit the risk of counterparty default, the Department has implemented a Wholesale Marketing Counterparty Evaluation Policy, which was amended and renamed as Counterparty Evaluation Credit Policy (the Counterparty Policy), and was approved by the Board on May 6, 2008. Under the new policy, the scope has been expanded beyond physical power to include transmission, physical natural gas, and financial natural gas. Also, the credit limit structure has been categorized into short-term and long-term structures where the short-term structure is applicable to transactions with terms of up to 18 months and the long-term structure to cover transactions beyond 18 months.

The Policy includes provisions to limit risk including: the assignment of internal credit ratings to all Department's counterparties based on counterparty and/or debt ratings; the use of expected default frequency equivalent credit rating for short-term transactions; the requirement for credit enhancements (including advance payments, irrevocable letters of credit, escrow trust accounts, and parent company guarantees) for counterparties that do not meet an acceptable level of risk; and the use of standardized agreements, which allow for the netting of positive and negative exposures associated with a single counterparty.

As of June 30, 2014, the 10 financial natural gas hedge counterparties were rated by Moody's as follows: three at Aa3, four at A2, one at Baa1, one at Baa2, and one WR. The counterparties were rated by S&P as follows: two at AA-, one at A+, five at A, and two at A-. As of June 30, 2013, the 10 financial natural gas hedge counterparties were rated by Moody's as follows: three at Aa3, three at A2, three at A3, and one at Baa1. The counterparties were rated by S&P as follows: two at AA-, two at A+, four at A, and two at A-.

Based on the International Swap Dealers Association agreements, the Department or the counterparty may be required to post collateral to support the financial natural gas hedges subject to credit risk in the form of cash, negotiable debt instruments (other than interest-only and principal-only securities), or eligible letters of credit. Collateral posted is held by a custodian. As of June 30, 2014 and 2013, the fair values of the financial natural gas hedges are within the credit limits and collateral posting was not required.

(c) Basis Risk

The Department is exposed to basis risk between the financial natural gas hedges, which are settled monthly at NW Rocky Mountains Index, and the hedged gas deliveries, which are daily spot purchases at Kern River, Opal prices. However, these pricing points are in the same region and are highly correlated.

(d) Termination Risk

The Power System or its counterparties may terminate the contractual agreements if the other party fails to perform under the terms of the contract. No termination events have occurred and there are no out-of-the-ordinary termination events contained in contractual documents.

(10) Long-Term Debt

Long-term debt outstanding as of June 30, 2014 and 2013 consists of revenue bonds and refunding revenue bonds due serially in varying annual amounts as follows (amounts in thousands):

Bond issues	Date of issue	Effective-interest rate%	Fiscal year of last scheduled maturity	Principal outstanding 2014	Principal outstanding 2013
Issue of 2001, Series B	06/05/01	Variable	2035	$ 580,800	580,800
Issue of 2001, Series C1	11/15/01	4.788	2017	2,008	2,003
Issue of 2002, Series A	08/22/02	Variable	2036	388,500	388,500
Issue of 2002, Series C2	11/22/02	4.375	2018	5,403	5,475
Issue of 2003, Series A1	07/31/03	3.409	2017	—	37,600
Issue of 2003, Series A2	08/19/03	4.662	2032	—	—
Issue of 2003, Series B	08/28/03	5.013	2036	—	4,245
Issue of 2004, Series C3	04/07/04	4.298	2020	7,147	7,147
Issue of 2005, Series A1	12/28/05	4.700	2041	530,285	530,285
Issue of 2005, Series A2	12/28/05	4.700	2031	315,195	315,195
Issue of 2006, Series C4	03/01/06	4.040	2017	5,149	5,149
Issue of 2007, Series A1	10/18/07	4.659	2040	330,630	330,630
Issue of 2007, Series A2	10/18/07	4.638	2033	191,125	191,125
Issue of 2008, Series A1	11/25/08	5.583	2039	200,000	200,000
Issue of 2008, Series A2	11/25/08	5.039	2033	330,880	336,840
Issue of 2009, Series A	02/19/09	4.773	2040	119,425	120,410
Issue of 2009, Series B	06/02/09	4.563	2025	172,125	172,125
Issue of 2010, Series A	06/02/10	3.898	2041	616,000	616,000
Issue of 2010, Series B	06/02/10	3.015	2023	38,675	45,600
Issue of 2010, Series C	08/25/10	2.188	2028	139,775	139,775
Issue of 2010, Series D	12/02/10	4.342	2046	760,200	760,200
Issue of 2011, Series A	06/30/11	2.715	2023	564,430	640,290
Issue of 2012, Series A	10/25/12	2.936	2036	104,075	104,075
Issue of 2012, Series B	10/25/12	4.164	2044	350,000	350,000
Issue of 2012, Series C	10/25/12	0.958	2016	300,000	300,000
Issue of 2013, Series A	04/02/13	2.504	2032	526,570	527,310
Issue of 2013, Series B	06/04/13	3.347	2033	452,145	452,145
Issue of 2013, Series C	06/04/13	4.441	2038	27,855	27,855
Issue of 2014, Series A	05/06/14	Variable	2039	200,000	—
Issue of 2014, Series B	06/10/14	4.008	2044	322,000	—
Total principal amount				7,580,397	7,190,779
Revenue certificates				200,000	200,000
Unamortized premiums and discounts				384,358	383,730
Debt due within one year (including current portion of variable rate debt)				(227,575)	(249,245)
				$ 7,937,180	7,525,264

Revenue bonds generally are callable 10 years after issuance. The Department has agreed to certain covenants with respect to bonded indebtedness. Significant covenants include the requirement that the Power Systems' net income, as defined, will be sufficient to pay certain amounts of future annual bond interest and of future annual aggregate bond interest and principal maturities. Revenue bonds and refunding bonds are collateralized by the future revenues of the Power System.

(a) ***Long-Term Debt Activity***

The Power System had the following activity in long-term debt for the fiscal years ended June 30, 2014, and 2013 (amounts in thousands):

		Balance, July 1, 2013	Additions	Reductions	Balance, June 30, 2014	Current portion
Long-term debt:						
Bonds	$	7,574,509	567,341	(177,095)	7,964,755	207,575
Revenue certificates		200,000	—	—	200,000	20,000
Total	$	7,774,509	567,341	(177,095)	8,164,755	227,575

		Balance, July 1, 2012	Additions	Reductions	Balance, June 30, 2013	Current portion
Long-term debt:						
Bonds	$	6,436,223	2,054,674	(916,388)	7,574,509	229,245
Revenue certificates		200,000	—	—	200,000	20,000
Total	$	6,636,223	2,054,674	(916,388)	7,774,509	249,245

(b) ***New Issuances***

Fiscal Year 2014

In May 2014, the Power System issued $200 million of variable rate Power System Revenue Bonds, 2014 Series A under a Direct Purchase structure. The net proceeds of $200 million were deposited into the construction fund to be used for capital improvements.

In June 2014, the Power System issued $322 million of Power System Revenue Bonds, 2014 Series B. The net proceeds of $366.42 million, including a $44.42 million issue premium net of underwriter's discount, were deposited into the construction fund to be used for capital improvements.

Fiscal Year 2013

In October 2012, the Power System issued $104.08 million of Power System Revenue Bonds, 2012 Series A. The net proceeds of $123.86 million, including a $19.78 million issue premium net of underwriter's discount, were used to refund a portion of the Power System Revenue Bonds, 2003 Series B amounting to $119.91 million. The transaction resulted in a net present value savings of

$25.55 million and a net loss for accounting purposes of $4.82 million, which was capitalized and is being amortized over the life of the new bonds.

Also, in October 2012, the Power System issued $350 million and $300 million of Power System Revenue Bonds, 2012 Series B and Series C, respectively. The net proceeds of $733.31 million, including a $83.31 million issue premium net of underwriter's discount, were deposited into the construction fund to be used for capital improvements.

In April 2013, the Power System issued $527.31 million of Power System Revenue Bonds, 2013 Series A. The net proceeds of $631.90 million, including a $104.59 million issue premium net of underwriter's discount, were used to refund a portion of the Power System Revenue Bonds, 2003 Series A, Subseries A-1, amounting to $108.50 million and all of the $515.83 million outstanding Power System Revenue Bonds, 2003 Series A, Subseries A-2. The transaction resulted in a net present value savings of $104.73 million and a net loss for accounting purposes of $11.90 million, which was capitalized and is being amortized over the life of the new bonds.

In June 2013, the Power System issued $452.15 million of Power System Revenue Bonds, 2013 Series B. The net proceeds of $533.14 million, including a $80.99 million issue premium net of underwriter's discount, were deposited into the construction fund to be used for capital improvements.

Lastly, in June 2013, the Power System issued $27.86 million of Power System Revenue Bonds, 2013 Series C. The net proceeds of $27.74 million, excluding a $0.12 million underwriter's discount, were deposited into the construction fund to be used for renewable energy projects. The Power 2013 Series C Bonds, designated as direct payment Qualified Energy Conservation Bonds (QECBs), enabled the Department to receive subsidy payments from the U.S. Treasury equal to 3.14% representing 70.00% of the tax credit rate of 4.49% (the credit rate determined under Section 54(A)(b)(3) of the Internal Revenue Code of 1986). The financing provided a weighted average life of 24.1 years, an average coupon rate of 4.41%, and an effective-interest rate of 1.29% (net of the tax subsidy).

(c) Outstanding Debt Defeased

The Power System defeased certain revenue bonds in current and prior years by placing cash or the proceeds of new revenue bonds in irrevocable trusts to provide for all future debt service payments on the old bonds. Accordingly, the trust account assets and the liability for the defeased bonds are not included in the Power System's financial statements.

At June 30, 2014, the following revenue bonds outstanding are considered defeased (amounts in thousands):

Bond issues		Principal outstanding
Second issue of 1993	$	6,900
Refunding issue of 1994		11,185
Issue of 1994		4,600
	$	22,685

(d) Variable Rate Bonds

In May 2014, the Power System entered into a Continuing Covenant Agreement (CCA) with Wells Fargo Bank whereby the former will sell to the later, $200 million of Power System Revenue Bonds, 2014 Series A in an index-floating rate mode under a Direct Purchase structure. The Bonds will pay interest at a fixed spread of 20 basis points (0.20%) above the Securities Industry and Financial Markets Association (SIFMA) Index for the initial three-year term. At the end of the three-year term, the Power System would have the option to either renegotiate and renew a new index floating rate term with Wells Fargo or another bank, or convert the bonds to another mode, such as a fixed rate mode or a traditional variable rate mode that utilizes a standby agreement. Under the terms of the CCA, the Power System has the option to call the bonds at par any time after one year with a 30-day notice.

As of June 30, 2014 and 2013, the Power System had $1.169 billion and $969.3 million in variable rate bonds, respectively. The variable rate bonds currently bear interest at weekly and daily rates ranging from 0.01% to 0.26% as of June 30, 2014 and 0.04% to 0.06% as of June 30, 2013. The Power System can elect to change the interest rate period of the bonds with certain limitations. The bondholders have the right to tender the bonds to the tender agent on any business day with seven days' prior notice. The Power System has entered into standby and line-of-credit agreements with a syndicate of commercial banks in an initial amount of $580.8 million and $388.5 million to provide liquidity for the variable rate bonds. The extended standby agreements expire in February 2015 for the $268.8 million, February 2016 for the $206 million, February 2017 for the $106 million for a total of $580.8 million; and in June 2017 for the $388.5 million.

Under the agreements, the $580.8 million variable rate bonds will bear interest that is payable quarterly at the greatest of: (a) the Prime Rate plus 1.00%; (b) the Federal Funds Rate plus 2.00%; and (c) 7.50%, while the $388.5 million variable rate bonds will bear interest that is payable quarterly at the greatest of: (a) the Prime Rate plus 2.00%; (b) the Federal Funds Rate plus 2.00%; (c) the Daily One-Month LIBOR plus 0.5%; and (d) 7.50%. The unpaid principal of each liquidity advance made by the liquidity provider is payable in 10 equal semiannual installments ninety days immediately following the related liquidity advance. At its discretion, the Power System has the ability to convert the outstanding bonds to fixed rate obligations, which cannot be tendered by the bondholders.

The variable rate bonds have been classified as long-term in the statement of net position as the liquidity facilities give the Power System the ability to refinance on a long-term basis and the Power System intends to either renew the facility or exercise its right to tender the debt as a long-term financing. The portion that would be due in the next fiscal year in the event that the outstanding variable rate bonds were tendered and purchased by the commercial banks under the standby agreements has been included in the current portion of long-term debt and was $96.9 million at both June 30, 2014 and 2013.

(e) Revenue Certificates

As of June 30, 2014 and 2013, the Power System has outstanding $200 million of commercial paper bearing interest at an average rate of 0.12%. The commercial paper matures not more than 270 days from the date of issuance.

The Department entered into a letter-of-credit and reimbursement agreement (the Agreement) with a commercial bank in the amount of $200 million to provide liquidity and credit support for the Department's commercial paper program. The agreement secures the payment when due of the principal and interest on commercial paper issued on or after July 1, 2013. Drawings on the agreement will represent advances to the Department and will bear interest that is payable monthly at the highest of (i) the Prime Rate plus 1.00%, (ii) Federal Funds Rate plus 2.00%, (iii) the Daily One-Month LIBOR plus 3.00%, and (iv) 7.00%. The unpaid principal of each advance is payable in 10 equal semiannual installments, commencing on the date six months after the advance. The Agreement terminates on July 1, 2016.

The revenue certificates have been classified as long-term debt in the statement of net position as the Agreement gives the Power System the ability to refinance on a long-term basis and the Power System intends to either renew the Agreement or exercise its option to draw on the Agreement. The portion that would be due in the next fiscal year in the event that the outstanding revenue certificates were advanced by the commercial bank under the Agreement has been included in the current portion of long-term debt and was $20 million at both June 30, 2014 and 2013.

(f) Scheduled Principal Maturities and Interest

Scheduled annual principal maturities and interest are as follows (amounts in thousands):

		Principal	Interest and amortization
Fiscal year(s) ending June 30:			
2015	$	110,645	293,297
2016		115,360	302,462
2017		118,751	315,386
2018		161,839	318,283
2019		169,526	317,165
2020–2024		996,903	1,487,520
2025–2029		1,270,846	1,254,497
2030–2034		1,496,990	948,796
2035–2039		1,336,296	658,678
2040–2044		1,450,700	283,942
2045–2049		352,541	12,922
Total requirements	$	7,580,397	6,192,948

Interest and amortization are net of $357.56 million of unamortized discount/premium and gain/loss due to issuances of new and refunding bonds.

The maturity schedule presented above reflects the scheduled debt service requirements for all of the Power System's long-term debt. The schedule is presented assuming that the tender options on the variable rate bonds, as discussed on the previous page, will not be exercised and that the full amount of the revenue certificates will be renewed. Should the bondholders exercise the tender options and the Power System convert all of the revenue certificates under the line of credit, the Power System would be required to redeem the $1,369.3 million in variable rate bonds and revenue certificates outstanding over the next six years, as follows: $116.93 million in fiscal year 2015, $233.86 million in fiscal year 2016, $433.86 million in fiscal year 2017, $233.86 million in each of the fiscal years 2018 through 2019, and $116.93 million in fiscal year 2020. Accordingly, the statements of net position recognize the possibility of the exercise of the tender options and reflect the $116.93 million that could be due in fiscal year 2015 as a current portion of long-term debt payable. Interest and amortization include interest requirements for variable rate bonds. Variable debt interest rate in effect at June 30, 2014 averages 0.100%.

(11) Retirement, Disability, and Death Benefit Insurance Plan

The Department has a funded contributory retirement, disability, and death benefit insurance plan covering substantially all of its employees. The Water and Power Employees' Retirement, Disability, and Death Benefit Insurance Plan (the Plan) operates as a single-employer defined benefit plan to provide pension benefits to eligible department employees and to provide disability and death benefits from the respective insurance funds. Plan benefits are generally based on years of service, age at retirement, and the employee's highest 12 consecutive months of salary before retirement. Active participants who joined the Plan on or after June 1, 1984 are required to contribute 6% of their annual covered payroll. Participants who joined the Plan prior to June 1, 1984 contribute an amount based upon an entry-age percentage rate. A new Tier 2 was added to the Plan and applies to members hired on or after January 1, 2014. Tier 2 plan participants are required to contribute 10% of their salary and plan benefits are based on a three-year final average salary period.

The Department contributes $1.10 for each $1.00 contributed by participants plus an actuarially determined annual required contribution (ARC) as determined by the Plan's independent actuary, taking into consideration the amount of net pension asset or obligation currently recorded in the statement of net position. The required contributions are allocated between the Power System and the Water System based on the current year labor costs.

The Retirement Board of Administration (the Retirement Board) is the administrator of the Plan. The Plan is subject to provisions of the Charter of the City and the regulations and instructions of the Board. The Plan is an independent pension trust fund of the City.

Plan amendments must be approved by both the Retirement Board and the Board. The Plan issues separately available financial statements on an annual basis. Such financial statements can be obtained from the Department of Water and Power Retirement Office, 111 N. Hope, Room 357, Los Angeles, California 90012.

The annual pension cost (APC) and net pension asset for the Department's Plan consist of the following (amounts in thousands):

		Year ended June 30	
		2014	2013
Annual required contribution	$	425,785	408,475
Interest on net pension asset		(6,401)	(7,278)
Adjustment to annual required contribution		9,698	11,028
APC (including $161.1 million and $156.7 million of amounts capitalized in fiscal years 2014 and 2013, respectively)		429,082	412,225
Department contributions		(384,641)	(368,174)
Change in net pension asset		44,441	44,051
Net pension (asset) at beginning of year		34,127	(9,924)
Net pension liability (asset) at end of year	$	78,568	34,127

The Power System's allocated share of the Plan's APC and net pension asset consists of the following (amounts in thousands):

		Year ended June 30	
		2014	2013
Annual required contribution	$	289,534	277,763
Interest on net pension asset		(4,352)	(4,949)
Adjustment to annual required contribution		6,594	7,499
APC (including $100.1 million and $97.9 million of amounts capitalized in fiscal years 2014 and 2013, respectively)		291,776	280,313
Power System contributions		(257,015)	(247,749)
Change in net pension asset		34,761	32,564
Net pension liability (asset) at beginning of year		50,773	18,209
Net pension liability at end of year	$	85,534	50,773

ARCs are determined through actuarial valuations using the entry-age normal actuarial cost method. The actuarial value of assets in excess of the Department's Actuarial Accrued Liability (AAL) is being amortized by level contribution offsets over rolling 15-year periods effective July 1, 2000.

In accordance with actuarial valuations, the Department's required contribution rates are as follows:

Fiscal year	Normal cost	Deficit amortization	Contribution rate
2014	15.10%	30.44%	47.30%
2013	15.06	29.30	46.08

The significant actuarial assumptions include an investment rate of return of 7.75%, projected inflation adjusted salary increases of 3.50%, and cost-of-living increases of 3.00%. The actuarial value of assets is determined using techniques that smoothen the effects of short-term volatility in the market value of investments over a five-year period. Plan assets consist primarily of corporate and government bonds, common stocks, mortgage-backed securities, and short-term investments.

Trend information for fiscal years 2014, 2013, and 2012 for the Power System is as follows (amounts in thousands):

Year ended June 30		Net pension liability (asset)	Percentage of APC contributed		APC
2014	$	85,534	88%	$	291,776
2013		50,773	88		280,313
2012		18,209	87		250,497

(a) Disability and Death Benefits

The Power System's allocated share of disability and death benefit plan costs and administrative expenses totaled $19.4 million and $19.4 million for fiscal years 2014 and 2013, respectively.

(b) Funded Status and Funding Progress Based on Latest Actuarial Study

On September 16, 2014, the latest actuarial study as of July 1, 2014 was completed for the Department for fiscal year 2014. As of July 1, 2014, the Department's actuarial value of assets was $8.9 billion and AAL for benefits was $11.0 billion resulting in an Unfunded Actuarial Accrued Liability (UAAL) of $2.1 billion. The covered payroll (annual payroll of active employees covered by the Plan) was $900 million, and the ratio of the UAAL to the covered payroll was 233%.

As of July 1, 2013, the Department's actuarial value of assets was $7.96 billion and AAL for benefits was $10.1 billion, resulting in an UAAL of $2.14 billion. The covered payroll (annual payroll of active employees covered by the Plan) was $900 million, and the ratio of the UAAL to the covered payroll was 237%.

As of July 1, 2012, the Department's actuarial value of assets was $7.57 billion and AAL for benefits was $9.69 billion, resulting in an UAAL of $2.12 billion. The covered payroll (annual payroll of active employees covered by the Plan) was $887 million, and the ratio of the UAAL to the covered payroll was 239%.

Actuarial valuations of an ongoing plan involve estimates of the value of reported amounts and assumptions about the probability of occurrence of events far into the future. Examples include assumptions about future employment, mortality, and the salary increases. Amounts determined regarding the funded status of the Plan and the ARCs of the Department are subject to continual revision as actual results are compared with past expectations and new estimates are made for the future. The schedule of funding progress, presented as required supplementary information, presents information about whether the actuarial value of plan assets is increasing or decreasing over time relative to the AAL for benefits.

(12) Other Postemployment Benefit (Healthcare) Plan

(a) Plan Description

The Department provides certain other postemployment benefits (OPEB), such as medical and dental plans, to active and retired employees and their dependents. The healthcare plan is administered by the Department. The Retirement Board and the Board have the authority to approve provisions and obligations. Eligibility for benefits for retired employees is dependent on a combination of age and service of the participants pursuant to a predetermined formula. Any changes to these provisions must be approved by the Retirement Board and the Board. The total number of active and retired Department participants entitled to receive benefits was approximately 16,491 and 16,319 for the fiscal years ended June 30, 2014 and 2013, respectively.

The health plan is a single-employer defined benefit plan. During fiscal year 2007, the Retiree Health Benefits Fund (the Fund) was created to fund the postemployment benefits of the Department. The Fund is administered as a trust and has its own financial statements. Such financial statements can be obtained from the Department of Water and Power Retirement Office, 111 N Hope, Room 357, Los Angeles, California 90012.

(b) Funding Policy

The Department pays a monthly maximum subsidy of $1,704 for medical and dental premiums depending on the employee's work location and benefits earned. Participants choosing plans with a cost in excess of the subsidy they are entitled to are required to pay the difference.

Although no formal funding policy has been established for the future benefits to be provided under this plan, the Department has made significant contributions into the Fund during previous years. In fiscal year 2014, the Department paid $74.6 million in retiree medical premiums. In fiscal year 2013, the Department paid $69.1 million in retiree medical premiums. No additional transfers to the Fund were made in fiscal years 2014 and 2013. The Power System's portion of retiree medical premium payments was $50.7 million and $47.0 million for 2014 and 2013, respectively.

(c) Annual OPEB Cost and Net OPEB Obligation

The annual OPEB cost (expense) is calculated based on the employer ARC, an amount actuarially determined in accordance with the parameters of GASB Statement No. 45, *Accounting and Financial Reporting by Employers for Postemployment Benefits Other Than Pensions*. The ARC represents a level of funding that, if paid on an ongoing basis, is projected to cover normal cost under each year and amortize any unfunded actuarial liabilities (or funding excess) over a period not to exceed 30 years.

The following table shows the components of the Department's annual OPEB cost for the year, the amount actually contributed to the Plan, and changes in the net OPEB asset (amounts in thousands):

		Year ended June 30	
		2014	2013
Annual required contribution	$	60,676	49,496
Interest on net OPEB asset		(76,461)	(73,943)
Adjustment to annual required contribution		66,869	62,758
Annual OPEB costs		51,084	38,311
Department contributions made		(74,625)	(69,127)
Change in net OPEB asset		(23,541)	(30,816)
Net OPEB asset – beginning of year		(954,690)	(923,874)
Net OPEB asset – end of year	$	(978,231)	(954,690)

The following table shows the components of the Power System's share in annual OPEB cost for the year, the amount actually contributed to the Plan, and changes in the net OPEB asset (amounts in thousands):

		Year ended June 30	
		2014	2013
Annual required contribution	$	41,259	33,657
Interest on net OPEB asset		(51,993)	(50,281)
Adjustment to annual required contribution		45,471	42,675
Annual OPEB costs		34,737	26,051
Power System contributions made		(50,749)	(47,011)
Change in net OPEB asset		(16,012)	(20,960)
Net OPEB asset – beginning of year		(652,439)	(631,479)
Net OPEB asset – end of year	$	(668,451)	(652,439)

The Department's annual OPEB cost, the percentage of ARC contributed to the Plan, and the net postemployment asset for fiscal years 2014, 2013, and 2012 were as follows (amounts in thousands):

		2014	2013	2012
Annual OPEB cost	$	51,084	38,311	41,620
Percentage of OPEB costs contributed		146%	180%	244%
Net postemployment asset at end of year	$	978,231	954,690	923,874

The Power System's share in the annual OPEB cost, the percentage of ARC contributed to the Plan, and the net retirement asset for fiscal years 2014, 2013, and 2012 were as follows (amounts in thousands):

		2014	2013	2012
Annual OPEB cost	$	34,737	26,051	28,301
Percentage of OPEB costs contributed		146%	180%	244%
Net postemployment asset at end of year	$	668,451	652,439	631,479

(d) Funded Status and Funding Progress Based on Latest Actuarial Study

On October 14, 2014, the latest actuarial study as of July 1, 2014 was completed for fiscal year 2015. As of July 1, 2014, the Department's actuarial value of assets was $1.49 billion and AAL for benefits was $1.95 billion, resulting in a UAAL of $0.46 billion. The covered payroll (annual payroll of active employees covered by the Plan) was $900 million, and the ratio of the UAAL to the covered payroll was 51%.

As of July 1, 2013, the Department's actuarial value of assets was $1.33 billion and AAL for benefits was $1.74 billion, resulting in a UAAL of $0.41 billion. The covered payroll (annual payroll of active employees covered by the Plan) was $900 million, and the ratio of the UAAL to the covered payroll was 46%.

As of July 1, 2012, the Department's actuarial value of assets was $1.25 billion and AAL for benefits was $1.57 billion, resulting in a UAAL of $0.32 billion. The covered payroll (annual payroll of active employees covered by the Plan) was $887 million, and the ratio of the UAAL to the covered payroll was 36%.

Actuarial valuations of an ongoing plan involve estimates of the value of reported amounts and assumptions about the probability of occurrence of events far into the future. Examples include assumptions about future employment, mortality, and the healthcare cost trend. Amounts determined regarding the funded status of the Plan and ARCs of the Department are subject to continual revision as actual results are compared with past expectations and new estimates are made for the future. The schedule of funding progress, presented as required supplementary information, presents information about whether the actuarial value of plan assets is increasing or decreasing over time relative to the AAL for benefits.

(e) *Actuarial Methods and Assumptions*

Projections of benefits for financial reporting purposes are based on the substantive plan (the plan understood by the Department and the plan members) and include the types of benefits provided at the time of each valuation and the historical pattern of sharing of benefit costs between the Department and the plan members to that point. The actuarial methods and assumptions used include techniques that are designed to reduce the effects of short-term volatility in AAL and the actuarial value of assets, consistent with the long-term perspective of the calculations.

In the July 1, 2013 actuarial valuation, the entry age normal cost method was used. The actuarial assumptions include 7.75% discount rate, which represents the expected long term return on plan assets, and an annual healthcare cost trend rate of 8.0% initially, reduced by decrements to an ultimate rate of 5.00% over 7 years. Both rates include a 3.50% inflation assumption. The actuarial value of assets was determined using techniques that spread UAAL being amortized as a level percentage of projected payroll over a closed 30 year period with 22 years remaining.

In the July 1, 2012 actuarial valuation, the entry-age normal cost method was used. The actuarial assumptions include 7.75% discount rate, which represents the expected long-term return on plan assets, an annual healthcare cost trend rate of 8.50% initially, reduced by decrements to an ultimate rate of 5.00% over 7 years. Both rates include a 3.50% inflation assumption. The actuarial value of assets was determined using techniques that spread UAAL being amortized as a level percentage of projected payroll over a closed 30-year period with 23 years remaining.

In the July 1, 2011 actuarial valuation, the entry-age normal cost method was used. The actuarial assumptions include 7.75% discount rate, which represents the expected long-term return on plan assets, an annual healthcare cost trend rate of 9.00% initially, reduced by decrements to an ultimate rate of 5.00% over 10 years. Both rates include a 3.50% inflation assumption. The actuarial value of assets was determined using techniques that spread UAAL being amortized as a level percentage of projected payroll over a closed 30-year period with 24 years remaining.

(f) *Healthcare Reform Legislation*

The Patient Protection and Affordable Care Act (PPACA) was signed into law on March 23, 2010. One key provision of the PPACA is the assessment of the excise tax on high cost plans (Cadillac Plans) beginning in 2018. Under this act, a 40% excise tax applies to plans with costs exceeding certain annual thresholds for non-Medicare retirees aged 55–64 ($11,850 for single coverage; $30,950 for families coverage). For all other retirees the thresholds in 2018 are $10,200 for single coverage and $27,500 for family coverage. Significant uncertainties exist regarding the impact of the excise tax on high cost plans without further regulatory guidance. Management estimated the potential impact of this tax on the liability is based on unadjusted thresholds and assuming the tax is shared between the Department and its participants in the same way that the current costs are shared.

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The estimated impact of the 40% excise tax provision on high cost plans beginning in 2018, under the healthcare reform, is reflected in all actuarial valuation reports after July 1, 2010.

(13) Other Long-Term Liabilities and Deferred Inflows

(a) Other Long-Term Liabilities and Deferred Inflows

The Power System has the following other long-term liabilities and deferred inflows:

		Balance July 1, 2013	Additions	Reductions	Balance June 30, 2014	Current portion
Accrued liabilities	$	7,047	—	(1,720)	5,327	—
Deferred inflows:						
Purchased power		18,069	—	(18,069)	—	—
Rate stabilization		117,443	56,558	—	174,001	—
Other		2,811	—	(29)	2,782	—
	$	138,323	56,558	(18,098)	176,783	—
Accrued workers' compensation claims	$	52,221	4,429	—	56,650	—
Derivative instrument liabilities	$	67,275	—	(18,758)	48,517	—

		Balance July 1, 2012	Additions	Reductions	Balance June 30, 2013	Current portion
Accrued liabilities	$	8,767	—	(1,720)	7,047	—
Deferred inflows:						
Purchased power		45,165	—	(27,096)	18,069	18,069
Rate stabilization		113,000	4,443	—	117,443	—
Other		2,811	—	—	2,811	—
	$	160,976	4,443	(27,096)	138,323	18,069
Accrued workers' compensation claims	$	43,475	8,746	—	52,221	—
Derivative instrument liabilities	$	91,296	—	(24,021)	67,275	—

(b) Deferred Inflows from Regulated Business Activities

The Department has deferred inflows that are related to revenues collected from customers, but have not been earned. These funds are deferred and recognized as costs related to these deferrals are incurred.

Purchased Power Deferrals

During fiscal year 2006, the Board approved the suspension of deferring precollected purchased power costs and the reversal of the precollected purchased power costs recorded in prior years. The amount reversed is the cost of energy from IPP less the amount designated in rates for out-of-market purchased power costs. The reversal of the deferred credit is credited to retail sales. During fiscal years 2014 and 2013, the Power System reversed $18.1 million and $27.1 million, respectively, related to precollected purchase power costs. At June 30, 2014 and 2013, $0 and $18.1 million, respectively, remain as part of deferred inflows related to precollected purchased power costs.

Rate Stabilization Account

In April 2008, the City Council approved an amendment to the electric rate ordinance, which required the balance of the Rate Stabilization Account to be maintained separately from the Energy Cost Adjustment Account. The ordinance also directed that the deferred amount within the Energy Cost Adjustment Account be the beginning balance of the Rate Stabilization Account. During fiscal years 2014 and 2013, $56.6 million and $4.4 million, respectively, were deferred from the current year sales for resale. As of June 30, 2014 and 2013, the balance in the Rate Stabilization Fund was $174 million and $117.4 million, respectively.

(c) Accrued Workers' Compensation Claims

Liabilities for unpaid workers' compensation claims are recorded at their present value when they are probable of occurrence and the amount can be reasonably estimated. The liability is actuarially determined, based on an estimate of the present value of the claims outstanding and an amount for claim events incurred but not reported based upon the Department's loss experience, less the amount of claims and settlements paid to date. The discount rate used to calculate this liability at its present value was 4% at June 30, 2014 and 2013. The Department has third-party insurance coverage for workers' compensation claims in excess of $1 million.

Overall indicated reserves for workers' compensation claims, for both the Water System and the Power System, undiscounted, have increased from $91 million as of June 30, 2013 to $100 million as of June 30, 2014. The increase is mainly attributable to an increase in the number of cases filed at the Department. Workers' compensation claims typically take longer than one year to settle and close out. The entire discounted liability is shown as long-term in the statement of net position as of June 30, 2014 and 2013.

Changes in the Department's undiscounted liability since June 30, 2012 are summarized as follows (amounts in thousands):

		June 30		
		2014	2013	2012
Balance at beginning of year	$	90,894	74,300	69,155
Current year claims and changes in estimates		33,945	37,561	26,769
Payments applied		(25,320)	(20,967)	(21,624)
Balance at end of year	$	99,519	90,894	74,300

The Power System's portion of the discounted reserves as of June 30, 2014 and 2013 is $56.7 million and $52.2 million, respectively.

(14) Commitments and Contingencies

(a) *Transfers to the Reserve Fund of the City of Los Angeles*

Under the provisions of the City Charter, the Power System transfers funds at its discretion to the reserve fund of the City. Pursuant to covenants contained in the bond indentures, the transfers may not be in excess of the increase in net position before transfers to the reserve fund of the City of the prior fiscal year. Such payments are not in lieu of taxes and are recorded as a transfer in the statements of revenues, expenses, and changes in net position.

The Department authorized total transfers of $253 million and $247 million in fiscal years 2014 and 2013, respectively, from the Power System to the reserve fund of the City.

(b) *Palo Verde Nuclear Generating Station (PVNGS) Matters*

As a joint project participant in PVNGS, the Department has certain commitments with respect to nuclear spent fuel and waste disposal. Under the Nuclear Policy Act, the Department of Energy (DOE) is to develop facilities necessary for the storage and disposal of spent fuel and to have the first such facility in operation by 1998; however, the development of the repository designated at Yucca Mountain in the state of Nevada was postponed indefinitely for political reasons after DOE spent billions of dollars conducting feasibility studies. A Blue Ribbon Committee was formed by the federal government to look into other alternatives for nuclear waste disposal. In 2012, the committee submitted a final list of recommendations which include prompt efforts to develop a new geological disposal facility and one or more consolidated storage facilities, and early preparation for eventual large-scale transport of spent fuel to storage and disposal facilities.

Capacity in existing fuel storage pools at PVNGS was exhausted in 2003. A Dry Cask Storage Facility (also called the Independent Spent Fuel Storage Installation, ISFSI) was built and completed in 2003 at a total cost of $33.9 million (about $1.9 million for the Department). The facility has the capacity to store all the spent fuel generated by the plant until the end of its life in 2027. With the current operating license extension granted by the Nuclear Regulatory Commission, PVNGS is allowed to operate until 2047. The Dry Cask Storage Facility will be expanded as needed to accommodate additional spent fuel until it is removed by DOE.

The Department accrues for current nuclear fuel storage costs as a component of fuel expense as the fuel is used. The Department's share of spent nuclear fuel costs related to its indirect interest in PVNGS is included in purchased power expense.

Because of the DOE's inability to provide a disposal site, the PVNGS operating agent filed damages actions against the DOE to recover costs incurred by the PVNGS participants. A settlement was reached in August 2010 in the amount of $30.2 million from DOE of which $1.7 million is the Department's share of the settlement which covers costs incurred up to 2006. Additional cost recovery is being pursued for the period post-2006.

The Price Anderson Act (the Act) requires that all utilities with nuclear generating facilities share in payment for claims resulting from a nuclear incident. Participants in PVNGS currently insure potential claims and liability through commercial insurance with a $375 million limit; the remainder of the potential liability is covered by the industry-wide retrospective assessment program provided under the Act. This program limits assessments to a maximum of $118 million per reactor for each licensee for each nuclear incident occurring at any nuclear reactor in the United States; payments under the program are limited to $18 million per reactor, per incident, per year. Based on the Department's 5.70% direct interest, the Department would be responsible for a maximum assessment of $20 million per incident for all 3 units, limited to payments of $3 million per incident annually.

The NRC guidelines require improved security in immediate areas surrounding the reactor buildings. PVNGS has enlarged the protected area with the inclusion of an outage support facility, a new warehouse, a minor vehicle maintenance facility, and a fuel depot to reduce vehicular traffic in and out of the protected area. While some of these facilities have already been constructed and are currently in service, the estimated cost for the remaining facilities is approximately $1.1 million to the Department.

Other major capital projects that are currently in progress include the digital upgrade of the Generrex generator excitation system, the life extension of the Water Reclamation Facility's clarifiers, the spray pond concrete replacement, the Nuclear Administrative and Technical Manual replacement, and the construction of the Learning Center-In Processing facility. These, along with other regulatory plant modifications, are currently estimated at $235 million in 2014, which translates to approximately $13.4 million for the Department. Also anticipated in the long range plan are $224 million ($12.7 million for the Department) worth of capital projects which include the cooling tower life extension long range plan, upgrades to the high-pressure turbines and electro-hydraulic controls, and the replacement of the reactor coolant pumps, Control Element Drive Mechanism Control System (CEDMCS), plant cooling water pipelines, and the Site Work Management System (SWMS).

In response to the nuclear event in Fukushima, Japan, the NRC has required PVNGS to increase the redundancy in its power supply to emergency cooling systems, reinforce its spent fuel pool, accelerate the transfer of spent fuel from the pool to the dry cask storage, and add pipelines and

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associated equipment necessary for supplying additional cooling water to the reactors. To date, the station has purchased additional diesel generators, pumps, and fire trucks, and has also accelerated the movement of its spent fuel casks to the ISFSI. In addition to these, Palo Verde has allotted approximately $82 million (approximately $4.7 million for the Department) for Fukushima initiatives, which include fuel building modifications, an emergency equipment storage facility, temporary power connections, seismic and flood hazards validation, and corresponding mitigating strategies, among several others. Additional NRC-mandated requirements are anticipated, but the costs associated with these future projects are unknown at this time.

(c) *Environmental Matters*

Numerous environmental laws and regulations affect the Power System's facilities and operations. The Department monitors its compliance with laws and regulations and reviews its remediation obligations on an ongoing basis. The following topics highlight some of the major environmental compliance issues affecting the Power System:

Air Quality – Nitrogen Oxide (NOx) Emissions

The Power System's generating station facilities are subject to the Regional Clean Air Incentives Market (RECLAIM) NOx emission reduction program adopted by the South Coast Air Quality Management District (SCAQMD). In accordance with this program, SCAQMD established annual NOx allocations for NOx RECLAIM facilities based on historical emissions and type of emission sources operated. These allocations are in the form of RECLAIM trading emission credits (RTCs). Facilities that exceed their allocations may buy RTCs from other companies that have emissions below their allocations. The Department has a program of installing emission controls and purchasing RTCs, as necessary, to meet its emission requirements.

As a result of the installation of NOx control equipment and the repowering of existing units, the Department has sufficient RTCs to meet its native load requirements for normal operations.

Air Quality – Greenhouse Gas Emissions

In September 2006, the state of California adopted two new laws designed to reduce greenhouse gas (GHG) emissions in California. The first, Assembly Bill 32, the California Global Warming Solutions Act of 2006, requires the California Air Resources Board (ARB) to develop regulations to reduce statewide GHG emissions back to 1990 levels by 2020. In 2007, the ARB established California's 1990 GHG emissions baseline, and developed a mandatory reporting regulation to require California sources to report their GHG emissions annually starting with 2008 data. In December 2008, the ARB adopted its Initial AB 32 Climate Change Scoping Plan, which serves as California's blueprint for reducing GHG emissions.

The Initial Scoping Plan includes the following emission reduction measures applicable to the electricity sector: (1) increase renewable energy to 33%, (2) expand energy efficiency programs, (3) reduce SF6 emissions from gas insulated electrical switchgear, and (4) establish a GHG cap-and-trade program. The cap-and-trade program sets a statewide cap on GHG emissions beginning in January 2013, with the cap declining two to three percent per year from 2013 to 2020.

The cap-and-trade program covers GHG emissions from all electricity generated in California or imported from other states, in-state industrial and manufacturing facilities, as well as natural gas and transportation fuels consumed in California.

In May 2014, ARB adopted the First Update to the AB 32 Scoping Plan, which describes process made to meet the near-term objectives of AB 32 and establishes California's climate change priorities and activities over the next several years. It also states activities and issues facing California as it develops an integrated framework for achieving climate goals and federal clean air standards in California beyond 2020.

The second bill adopted by the state of California is designed to reduce greenhouse gas emissions from the generation of electricity consumed in California. Senate Bill 1368 requires the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC) to establish a greenhouse gas emissions performance standard and implement regulations governing long-term financial commitments in base load generation made by load serving entities (LSEs) including publicly owned electric utilities (POUs). These regulations are intended to prohibit any California LSE from entering into or renewing a long-term financial commitment with a base load generating resource that exceeds the greenhouse gas emissions performance standard, currently set at 1,100 pounds carbon dioxide per megawatt hour of electricity generated. This means that when existing contracts with high-emitting generating resources expire, those resources will be replaced by lower emitting generating resources that comply with the greenhouse gas emissions performance standard.

At the federal level, several legislative bills have been proposed or introduced, but none have passed Congress. However, the United States Environmental Protection Agency (EPA) adopted its Prevention of Significant Deterioration (PSD) and Title V Greenhouse Gas Tailoring Rule in June 2010, which established a phased timetable for implementing Clean Air Act permitting requirements for GHG emissions from new and modified major stationary sources. In June 2014, the U.S. Supreme Court held that the Clean Air Act does not permit EPA to adopt an interpretation of the Act requiring a source to obtain a PSD or Title V operating permit on the sole basis of its potential GHG emissions. The court also held that EPA reasonably interpreted the Clean Air Act to require sources that would need permits based on their emission of conventional pollutants to comply with Best Available Control Technology GHG requirements. The Power System's in-basin repowering projects would be subject to the permitting requirements under EPA's Tailoring Rule. Also, any new GHG requirements will be incorporated in the Power System's generating stations' Title V operating permits when the permits are renewed.

In addition to the PSD permit program, EPA is also in the process of developing a GHG regulatory program under the New Source Performance Standards (NSPS) provisions of the Clean Air Act. On December 23, 2010, the EPA entered a settlement agreement and agreed to issue NSPS and emissions guidelines for GHG emissions from new and modified fossil fuel fired electric generating units (EGUs). On April 13, 2012, the EPA published in the Federal Register its proposed rule for GHG NSPS for new EGUs. EPA received over 2.5 million comments, the most ever for a proposed EPA rule.

On June 25, 2013, President Obama announced initiatives addressing climate change. In his announcement, he directed EPA to repropose GHG emission standards for new EGUs by September 20, 2013. He also directed EPA to propose guidelines for existing EGUs by June 2014, and finalize them a year later.

EPA released the reproposed standards on September 20, 2013 and proposed to set an emission's limit of 1,100 pounds of CO2 per megawatt-hour (MWh) of electricity generated by new coal-fired EGUs, and an emission limit of either 1,000 or 1,100 lb/MWh (depending on size) for new natural gas-fired EGUs. Written comments were due to EPA on May 9, 2014. LADWP cannot predict the outcome of this rulemaking.

On June 18, 2014, EPA's proposed Clean Power Plan for reducing CO2 from existing power plants was published in the federal register. The proposal requires each state with fossil fuel-fired generation to meet state-specific rate-based (lb/MWh) CO2 emission goals by 2030 as well as an interim reduction target, which is an average emission rate required to be met over the period 2020 to 2029. The proposal also allows states to convert their emission rate goals to a mass-based limit (tons CO2/year) and provides guidelines for states to follow in developing plans to achieve the state-specific goals. Clean Air Act Section 111(d) provides states with the primary responsibility and authority to establish and implement performance standards for existing sources and states will have broad discretion to develop their plans. LADWP cannot predict how the guidelines will impact its operations at this time.

EPA Coal Combustion Residuals Proposed Rules

On June 21, 2010, the U.S. Environmental Protection Agency (EPA) proposed to establish federal standards to regulate coal combustion residuals (coal ash). The two options being considered are to designate coal ash as either hazardous or nonhazardous. The hazardous waste proposal would phase out the disposal of ash in wet storage ponds. The nonhazardous designation would set federal guidelines for state disposal that require the installation of additional liners on new wet storage pond. Both options set new requirements for storing and monitoring the waste in dry landfills.

The worst-case scenario impact at the Intermountain Power Plant would be $483 million in capital cost plus $110 million in annual operating cost for the hazardous option if the existing landfill has to be removed and coal ash has to be disposed of at an off-site facility. At this point, EPA has not proposed a clean closure of landfills and it is not a preferred option. For the nonhazardous option, the impact would be $62 million in capital cost plus $2 million in annual operating cost.

For Mohave Power Plant, the worst-case scenario impact would be $230 million in capital cost for the hazardous option if the existing landfill has to be removed and disposed of at an off-site facility. For the nonhazardous option, the impact would be $6 million in capital cost plus $0.25 million in annual operating cost.

For the above facilities, the costs translate into electric rate impacts of about 1.4% for the hazardous option and 0.18% for the nonhazardous option.

The EPA is under court order to take final action on a new rule by December 19, 2014.

Power Plant Once-through Cooling Water Systems

Once-through cooling (OTC) is the process where water is drawn from a source, pumped through equipment to provide cooling, and then discharged. Some type of cooling process is necessary for nearly every type of traditional electrical generating station, and the OTC process is utilized by many electrical generating stations located next to large bodies of water. Typically, the water used for cooling is not chemically changed in the process although its temperature is increased.

Due to the Second Circuit Court's decision to remand most of Environmental Protection Agency (EPA's) 316(b) Rule finalized in July 2004, EPA suspended this Rule and drafted a new rule that was signed by EPA on May 16, 2014, a prepublished version was released on May 19, 2014. Once the rule is published in the Federal Register, it becomes effective within 60 days. The new rule requirements applies to cooling water intake structures for all existing power generating facilities that withdraw more than 2 million gallons per day of water from waters of the United States and use at least 25% of the water they withdraw exclusively for cooling purposes. Under this rule, an owner or operator of an existing facility will be able to choose from seven different compliance options for impingement mortality (IM): Option 1 – operate a closed-cycle recirculating system; Option 2 – reduce the maximum design through screen velocity not to exceed 0.5 feet per second (fps) during minimum source water levels; Option 3 – demonstrate actual through screen velocity is less than or equal to 0.5 fps under all ambient conditions; Option 4 – Have an existing (minimum 800 feet offshore) velocity cap; Option 5 – install modified traveling water screens and optimize performance in a two-year study; Option 6 – integrated technologies, practices, and operational measures that are optimized in a two-year study; Option 7 – demonstrate that impingement mortality is reduced to no more than 24% annually based on monthly monitoring. In addition to these options, compliance requirements can be waived by the Permitting Director if it can be demonstrated that (1) impingement is de minimis, (2) if the capacity utilization rate is less than 8% averaged over a 24-month contiguous period, and (3) if the intake is located on a manmade lake or reservoir and the fishery is managed (but does not include any Federal threatened and endangered species or critical habitat). For entrainment mortality, the rule requires entrainment studies and evaluation of entrainment technologies (including closed cycle cooling, fine mesh/narrow slot screens, grey and reused water) as well as environmental impacts and benefits. Determination of compliance is by the permitting authority and could result in retrofitting to closed cycle cooling. The compliance schedule for both IM and E is on a "case by case" site-specific basis, determined by the Permitting Authority. The Department's compliance for IM and E and schedule has already been determined by its Permitting Authority, the State Water Resource Control Board, which is to eliminate the use of OTC by 2029 with closed cycle cooling. The Department is evaluating if there are any other potential impacts of the rule on its facilities.

During the absence of EPA's 316(b) Rule, the California State Water Resources Control Board (State Board) decided to move forward and adopted its own Statewide 316 b Policy (Policy) on May 4, 2010. The Policy became effective on October 1, 2010. This policy requires the Department's coastal power plants to reduce OTC by 93% – equivalent to wet cooling towers using seawater. This is referred to as the Track 1 compliance path. If the Track 1 compliance path is found to be infeasible, with concurrence from the State Board, a Track 2 compliance path can be pursued, which requires that the cooling water intake structure (CWIS) achieve an impingement mortality and entrainment (IM/E) reduction level of 90% of the Track I compliance standard or 83.7% on a unit-by-unit basis. The Department has made a decision to pursue the Track 1 compliance path, in order to comply with the Policy and completely eliminate the use of OTC. The Department was successful in having the Policy amended to extend the compliance dates, for six out of the nine remaining OTC units, to 2024 for Scattergood, and 2029 for Haynes and Harbor. The other three OTC units are on schedule, due to an SCAQMD settlement, to be repowered with eliminating OTC by 2013 and 2015, respectively. The Amendment to the Policy was adopted on July 19, 2011. The Amendment required the Department to submit additional information responsive to the Statewide Advisory Committee on Cooling Water Intake Structures (SACCWIS) resolution by December 31, 2012 in order for the State Board to decide whether or not modifications to the 2029 compliance dates were warranted. The additional information required by SACCWIS was submitted by LADWP and the State Board did not make any modifications to LADWP's 2029 compliance dates. Furthermore, the Amendment requires implementation of interim measures; these measures include a proposal to study new and/or viable existing technologies to reduce impingement and entrainment. The proposal must be submitted to the State Board no later than December 31, 2015. Upon approval of the proposal, the interim measures must be in place no later than December 31, 2020. These interim measures will include the funding of a mitigation project or the use of screens or an equivalent alternative measure at each OTC unit or intake until the facility is in full compliance.

In addition, other regulatory changes have been made that could significantly impact operations at the Haynes and Harbor Generating Stations. The Regional Water Quality Control Board reclassified the body of water that the OTC water is discharged to an enclosed bay for the Harbor Generating Station, and sent a letter of intent to reclassify the receiving water body of water as an estuary for the Haynes Generating Station discharge. Even though the Haynes Generating Station will be repowering existing units, should there be a reclassification for the water body discharges at the Haynes Generating Station, there will be requirements that cannot be met with its existing cooling or future repowered configuration. The Department is in the process of reviewing the regulations and conducting studies. Once the studies are reviewed, the Department will determine an appropriate course of action.

Pollution and Remediation Obligations

The Department follows GASB Statement No. 49, *Accounting and Financial Reporting for Pollution and Remediation Obligations* (GASB Statement No. 49). This statement addresses accounting and financial reporting standards for pollution (including contamination) remediation obligations, which are obligations to address the current or potential detrimental effects of existing pollution by participating in pollution remediation activities such as site assessments and cleanups. The scope of the statement excludes pollution prevention or control obligations with respect to current operations, and future pollution remediation activities that are required upon retirement of an asset, such as landfill closure and postclosure care and nuclear power plant decommissioning. The Power System's obligations were approximately $25.6 million and $26 million as of June 30, 2014 and 2013, respectively.

(d) *Litigation*

i. Capital Facilities Fee Claims

In June 2007, the Department received a tentative decision in favor of the state and a number of local government agencies that are electric customers of the Department that claimed that the Department has rates that include a capital facilities' charge that violates the state's statute. However, in October 2008, the Department settled the case and recorded the $160 million settlement amount. Additionally, as permitted by the regulatory accounting criteria set forth per the GASB Codification (GASB Statement No. 62), the Board approved to defer all potential costs associated with the resolution of this litigation and establish a corresponding long-term deferred debit to be recovered through future revenues over a period of up to 10 years, if necessary.

ii. Other

A number of claims and suits are also pending against the Department for alleged damages to persons and property and for other alleged liabilities arising out of its operations. In the opinion of management, any ultimate liability, which may arise from these actions, is not expected to materially impact the Power System's financial position, results of operations, or cash flows as of June 30, 2014.

(e) *Risk Management*

The Power System is subject to certain business risks common to the utility industry. The majority of these risks are mitigated by external insurance coverage obtained by the Power System. For other significant business risks, however, the Power System has elected to self-insure. Management believes that exposure to loss arising out of self-insured business risks will not materially impact the Power System's financial position, results of operations, or cash flows as of June 30, 2014.

(f) *Credit Risk*

Financial instruments, which potentially expose the Power System to concentrations of credit risk, consist primarily of retail and wholesale receivables. The Power System's retail customer base is concentrated among commercial, industrial, residential, and governmental customers located within the City. Although the Power System is directly affected by the City's economy, management does not believe significant credit risk exists at June 30, 2014, except as provided in the allowance for losses. The Power System manages its credit exposure by requiring credit enhancements from certain customers and through procedures designed to identify and monitor credit risk.

(Continued)

(g) Subsequent Events

In August 2014, the Power System issued $198.75 million of fixed rate Power System Revenue Bonds, 2014 Series C. The net proceeds of $235.40 million, including a $36.65 million issue premium net of underwriter's discount, were used to refund a portion of the Power System Revenue Bonds, 2005 Series A, Subseries A-1 and A-2 amounting to $27.0 million and $197.6 million, respectively. The transaction resulted in a net present value savings of $28.13 million and a net loss for accounting purposes of $7.47 million, which was deferred and is being amortized over the life of the new bonds.

In October 2014, the Power System issued $450 million of Power System Revenue Bonds, 2014 Series D. The net proceeds of $526.04 million, including a $76.04 million issue premium net of underwriter's discount, were deposited into the construction fund to be used for capital improvements to the Power System.

The Power System has evaluated subsequent events through December 8, 2014, the date the financial statements were available to be issued, and has determined that no other significant subsequent events have occurred through that date.

LOS ANGELES DEPARTMENT OF WATER AND POWER
POWER SYSTEM

Required Supplementary Information

June 30, 2014 and 2013

Pension Plan – Schedule of Funding Progress

The following schedule provides information about the Department's overall progress made in accumulating sufficient assets to pay benefits when due, prior to allocations to the Water System and the Power System (amounts in thousands):

Actuarial valuation date July 1		Actuarial value of assets	Actuarial accrued liability (AAL)	Unfunded AAL (UAAL)	Funded ratio		Covered payroll	UAAL as a percentage of covered payroll
2014	$	8,877,595	10,975,551	2,097,956	81%	$	900,126	233%
2013		7,958,488	10,094,868	2,136,380	79		900,254	237
2012		7,573,886	9,692,603	2,118,717	78		886,539	239

Postemployment Healthcare Plan – Schedule of Funding Progress

The following schedule provides information about the Department's overall progress made in accumulating sufficient assets to pay benefits when due, prior to allocations to the Water System and the Power System (amounts in thousands):

Actuarial valuation date July 1		Actuarial value of assets	Actuarial accrued liability (AAL)	Unfunded AAL (UAAL)	Funded ratio		Covered payroll	UAAL as a percentage of covered payroll
2014	$	1,485,140	1,947,912	462,772	76%	$	900,126	51%
2013		1,332,136	1,743,727	411,591	76		900,254	46
2012		1,244,039	1,566,059	322,020	79		886,539	36

See accompanying independent auditors' report.