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 LLP
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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.

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.

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

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

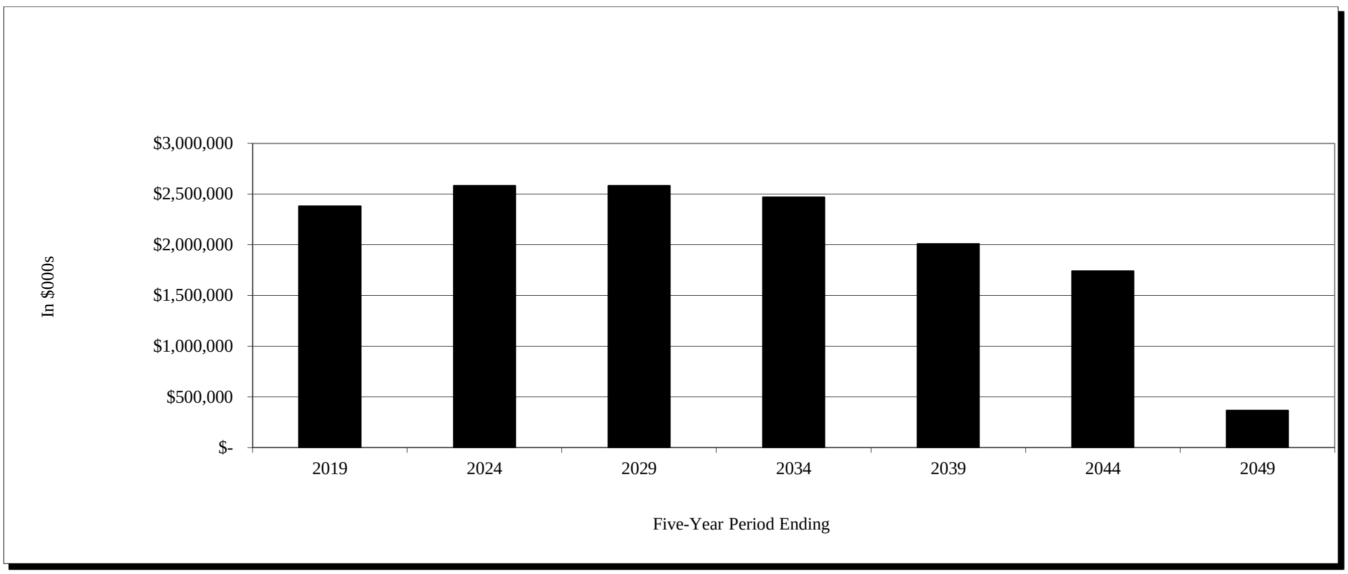
Long-Term Debt

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.

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

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).

(Continued)

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 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	Capacity (MWs)	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.

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):

		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	$ 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	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

(Continued)

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

(Continued)

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)

(Continued)

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.

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

(Continued)

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 1 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.

(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.

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.