10 CFR 50.71(b)

APS

Palo Verde Nuclear
Generating Station

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102-05762-TNW/CJJ
October 24, 2007

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

Dear Sirs:

Subject: Palo Verde Nuclear Generating Station (PVNGS)
Units 1, 2, and 3
Docket Nos. STN 50-528/529/530
Submittal of 2006 Annual Financial Reports

Pursuant to 10 CFR 50.71(b), enclosed please find copies of the 2006 Annual Financial Reports for the Participants who jointly own PVNGS and do not file a Form 10-Q with the Securities and Exchange Commission or a Form 1 with the Federal Energy Regulatory Commission. These Participants are Salt River Project, Southern California Public Power Authority, and Los Angeles Department of Water and Power.

The remaining Participants who jointly own PVNGS file a Form 1 with the Federal Energy Regulatory Commission and are thereby exempt from filing an Annual Financial Report. These Participants are Southern California Edison Company, El Paso Electric Company, Arizona Public Service Company and Public Service Company of New Mexico.

No commitments are being made to the NRC by this letter. Should you have any questions, please contact Glenn A. Michael at (623) 393-5750.

Sincerely,

Thomas N. Weber

Enclosure

TNW/GAM/CJJ/gat

cc:		
	E. E. Collins Jr.	NRC Region IV Regional Administrator (w/o Enclosure)
	M. T. Markley	NRC NRR Project Manager (w/o Enclosure)
	G. G. Warnick	NRC Senior Resident Inspector for PVNGS (w/Enclosure)

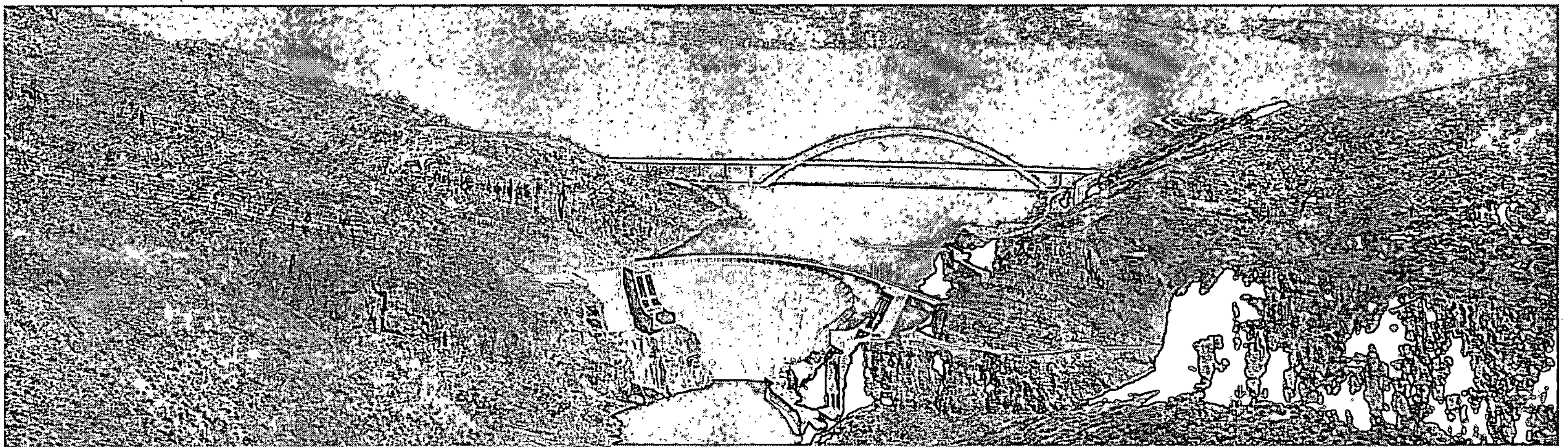
M004
NRR

ENCLOSURE

PALO VERDE NUCLEAR GENERATING STATION

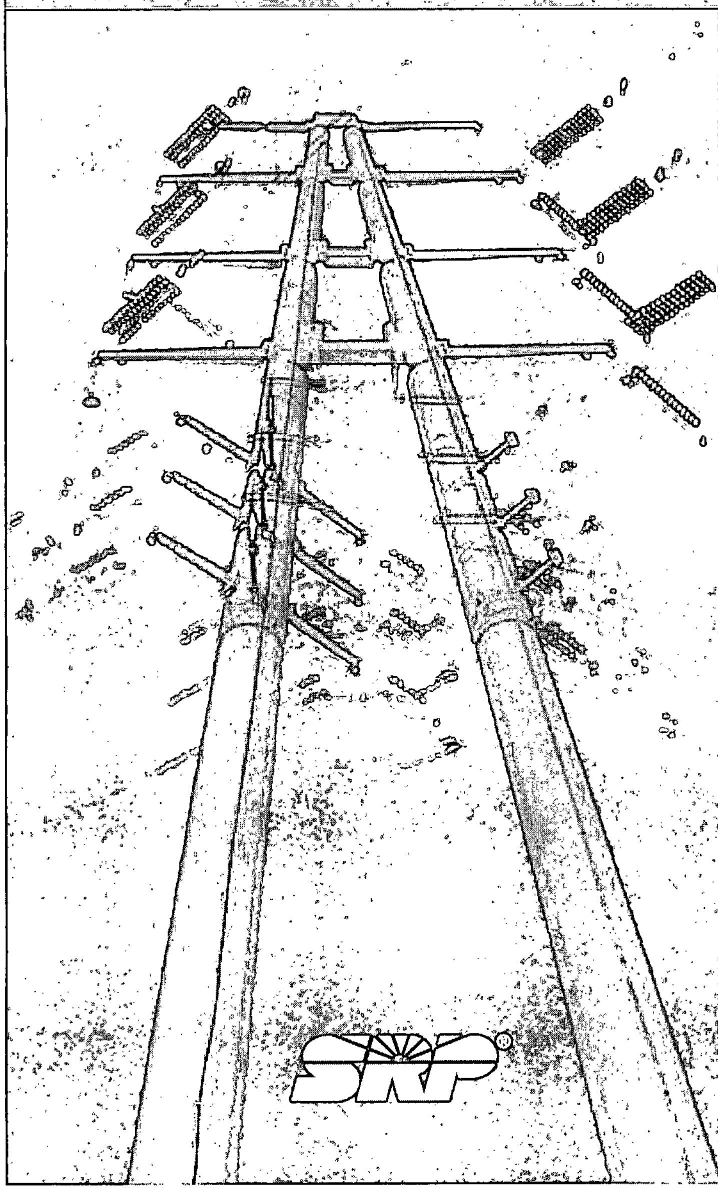
2006 ANNUAL FINANCIAL REPORTS

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



INVESTING in the FUTURE

2006 Salt River Project Annual Report



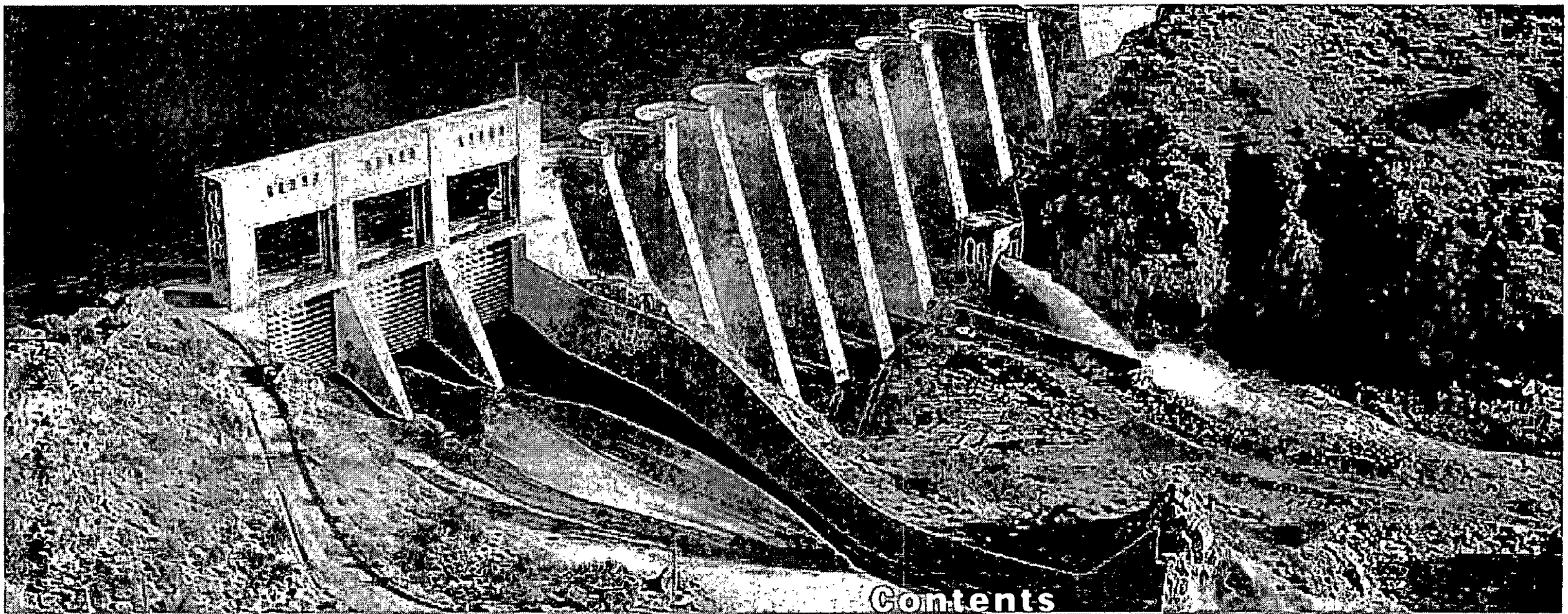
About SRP

SRP provides electricity to more than 2 million people in a 2,900-square-mile area in Central Arizona, an area known as the "Valley." Founded in 1903, SRP is an integrated electric utility, providing generation, transmission and distribution services.

SRP also is the greater Phoenix metropolitan area's largest water supplier, with a water service area that spans 375 square miles. In addition, SRP manages the 13,000-square-mile watershed that supplies a majority of our water service area's surface water.

From humble beginnings to one of the largest public power entities in the nation, SRP remains an organization of capable local people working together to serve local needs.

Our mission is clear: "The mission of Salt River Project is to deliver ever-improving contributions to the people we serve through the provision of low-cost, reliable water and power, and community programs, to ensure the vitality of the Salt River Valley."



Contents

David Rousseau and John M. Williams Jr.

Letter to Our Electric Customers, Water Shareholders and Bondholders

John M. Williams Jr. was elected SRP president in April 2006. Mr. Williams had served as vice president of SRP since 1994 and has been a member of SRP boards and councils for 28 years. David Rousseau was elected vice president. Mr. Rousseau brings 16 years of SRP boards and councils experience to the office of vice president.

We are pleased to report another year of successes for SRP.

Through the expansion and upgrade of our electric system, we are keeping pace with electric customer growth that consistently increases at twice the national average. Over the past six years, our capital expansion and improvement projects totaled more than $3.2 billion. This year we continued to prepare for new generating resources as well as transmission, distribution and many other projects to help meet the ever-increasing demand for electricity. Our efficient and reliable power system now supports and provides for nearly 893,000 retail customers.

To plan for and manage growth, our management team works from a six-year financial plan that is fine-tuned annually, remaining flexible to address changes in the marketplace. Notably, this plan includes an emphasis on sustainable energy sources and technologies, diverse generation resources, and offering smart and easy ways for our customers to conserve.

Population growth has its effects on water, too. In some rural areas – where much of the state's urban water supplies originate and historically where little water use existed – residential growth is outstripping locally available supplies. This places pressure on the future water sources for those we serve in our 375-square-mile water service area, which includes portions of many Valley communities. Subsequently, SRP and rural communities are working together to develop a water stewardship culture though education and conservation. We also collaborate with policy makers to define the region's water rights and to bring certainty and assurance to our water service area.

Meanwhile, persistently dry conditions raise further awareness of the record-setting drought Arizona is experiencing. The fact that no rain fell for 143 days this past winter underscores the reality that we are subject to the wiles of a desert environment.

Fortunately, SRP has the infrastructure needed to manage available water supplies. Our system of dams, canals, laterals, wells and underground storage sustains the economic well-being of the area. This year, the system demonstrated the inherent beauty of its design: Even though the year was dry, reservoir storage at year-end was a healthy 74 percent of capacity, because of wet conditions the previous winter. Among other things, this meant we were able to sustain water deliveries without reducing allocations.

As we continue to invest in the future of our communities, strong earnings are essential. For the year, financial results were outstanding. Net revenues were $415.4 million on total operating revenues of $2.5 billion. Many factors influenced the year's revenues, including energy sales growth, sound cost-management practices, a retail price increase and an extraordinary gain from the reinvestment of monies in our nuclear decommissioning fund and post-retirement medical fund.

This year, SRP reduced its debt-to-capitalization ratio by 2.2 percent, to 47.9 percent, the lowest in more than 50 years. Our solid financial performance also allowed us to hold high credit ratings: Moody's Investors Service recently raised our rating to Aa1, and we hold an AA rating from Standard & Poor's.

SRP today reflects the same spirit of commitment that our founders demonstrated more than a century ago. Indeed, one of the defining characteristics of this organization is our people — and the shared vision of delivering outstanding customer service. This commitment to our customers is supported at the highest levels of SRP leadership. We take this opportunity to say "Thank You" to SRP's employees, who place service excellence at the top of their agendas every day.

This spring, SRP experienced a transition in the president and vice president roles. We are proud and excited to take on these new responsibilities. And we look forward to the year ahead with confidence and enthusiasm.

John M. Williams Jr.
President

David Rousseau
Vice President

We wish to acknowledge the dedication and guidance of William P. Schrader, who retired this spring after 42 years of service to SRP, the last 12 as president.

Letter from the General Manager

SRP had another successful year. Financial results exceeded expectations and growth remains robust, though moderated when compared to last fiscal year.

Our reservoirs, replenished during the 2004-2005 runoff season, while not full are at respectable levels. However, it does appear the drought has resumed, and we are once again planning for an extended dry cycle.

SRP's heritage of water stewardship continues to be of utmost importance. Implementation of the Arizona Water Settlements Act remains a high priority. This past year we have made some progress in resolving conflicting claims to the underflow and aquifers of the Verde River and its watershed. And, we have achieved significant milestones in our efforts to absorb C. C. Cragin Reservoir (formerly Blue Ridge) into the Salt River Federal Reclamation Project.

Our recently initiated decade-long program with Valley cities to increase groundwater pumping capability for drought protection has advanced through the planning stage. Working together we are confident we can meet the challenges of co-locating a substantial number of new wells in an essentially urban area.

Turning to the electric side of the business, we have devoted much effort to the federal government's implementation of the national Energy Policy Act of 2005. We have actively participated in Federal Energy Regulatory Commission (FERC) efforts as it has proposed implementing steps directed to the wholesale electric market. Also, we continue to monitor leadership changes at FERC, which have resulted in a re-examination of certain of its policies.

There has been no resumption of efforts to revive retail competition in Arizona. While dormant here, efforts nationwide remind us it could re-appear.

Changes in SRP's electric infrastructure have been significant. The Mohave Generating Station closed December 31, 2005, because sulfur dioxide emission control equipment, required by a consent decree, had not been installed. Recently the majority owner of this plant, in which SRP owns 20 percent, announced it would no longer retain ownership because of the uncertainty of future operation. The owners currently are determining the future of the plant, including the possibility of new ownership. Also under study is an alternative water supply for the 270-mile coal-slurry pipeline from the Black Mesa Mine to the plant.

During the year we added Unit 6 at the natural-gas-fired Santan Generating Station, which improves reliability by adding local generation in our service territory, and enhancing import capability. Springerville Unit 3 has been completed, providing by contract, 100 megawatts (MW) to SRP, and SRP began construction of Unit 4. Both are 400MW coal-fired base load units. This past year various utilities have announced collaborative plans to file applications for the first new nuclear units in decades. We are watching this activity closely, as it develops.

Additional extra-high voltage transmission remains a key focus in our region, as we continue to plan, permit and construct new facilities for our growing service area. This needed infrastructure has occurred even as other areas of the country lag the need.

Our service territory is in an enviable growth area. The Arizona economy continues to outperform the United States. The greater Phoenix metropolitan area's employment base rate is expected to grow 3.4 percent over the next 4 years.

New customer installation design requests, while moderating, continue at respectable levels. Slower growth scenarios we undertake on a regular basis demonstrate we can deal with that, if necessary.

We have been participating in a planning effort seeking to develop a substantial parcel of state trust land in the southeastern portion of our service territory, in northeastern Pinal County. This area, if developed, will provide significant growth for SRP, and we are planning to assure we are prepared. Our service territory, the greater Phoenix metropolitan area, is 4th in the U.S. with respect to population growth among larger urban areas.

Costs of fuel for production of electricity, as is the case everywhere, continue to escalate, notwithstanding prudent control efforts. Pricing actions, necessary to continue SRP's financial well being, were implemented. However, we have been able to mitigate customer impacts by approaches such as fuel hedging and effective use of SRP's rate stabilization fund. Price volatility of natural gas, the fuel for local generating plants, has moderated to some extent, while efforts to explore local storage opportunities continue.

SRP's strong commitment to the environment is reflected in the board action this past year, increasing our sustainability portfolio to 15 percent by 2025. Included are plans for increasing energy produced by geothermal, biomass, wind and solar. Also included is growth in our pre-paid metering program, and other conservation programs. Dealing with global warming, an issue in which political reality has overtaken science, presents its own set of challenges, and so we participate in activities devoted to understanding and dealing with this phenomena.

In addition to pre-paid metering, the elements of SRP's customer service program continue to grow and be recognized. During the year, strong increases in participation were recorded in SRP's Custom Due Date, Managed Payment Plan, Surepay, Time of Use, e-Chex, Spanish Bills and Spatia (commercial load resource) programs. We introduced "paperless billing" this year as well, and in combination with other services available on "srpnet.com" recorded more than 2.3 million user sessions over the Internet.

SRP was ranked first in the nation in overall residential electric customer satisfaction in the 2006 J.D. Power and Associates study. In addition, J.D. Power and Associates recognized SRP as "best in the west" for commercial customer satisfaction, and certified our phone centers for providing "an outstanding, customer service experience."

We continue to meet the challenge of an aging workforce. Our development, mentoring, apprenticeship, rotational and other programs continue SRP as a benchmark organization. We are confident our proactive planning efforts will enable us to effectively manage for the future personnel changes vital to continued success.

SRP's hard working employees are responsible for the year's results. And, the dedication of our elected officials contributes substantially to our success.

Richard H. Silverman

Richard H. Silverman
General Manager

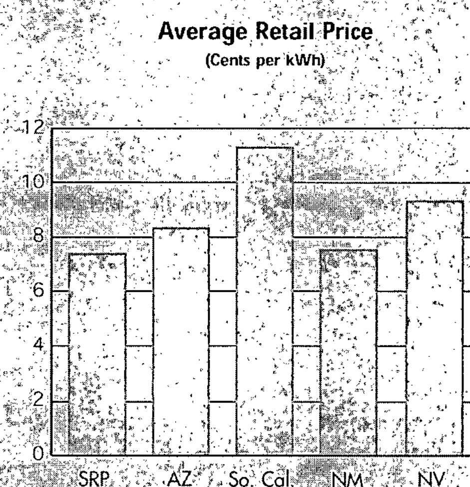
Building for the Future

- Provide a secure, efficient energy supply
- Deliver reliable electricity at affordable prices
- Offer customers innovative solutions

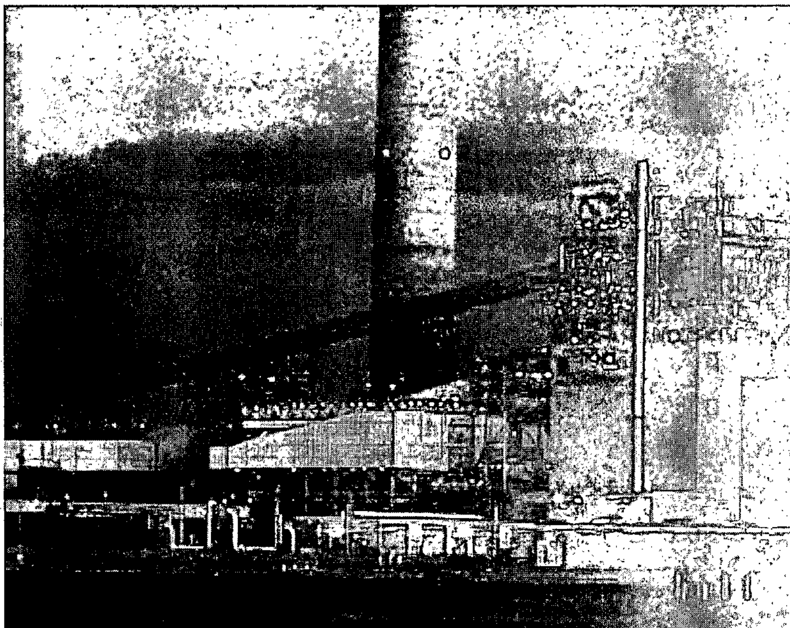
Arizona is hot in more ways than one, ranking again as the second-fastest-growing state in the country.

SRP provides electricity to the most heavily populated region of the state – central Arizona, commonly referred to as "the Valley" – where Phoenix and several other of the nation's fastest-growing cities are located. The dynamics of the region demand that we excel in our business. And because we do excel, everyone in our communities benefits.

SRP's efforts support efficient, reliable and affordable electricity – today and for the future. We balance this commitment with continued attention to achieving the best productivity from our electric facilities – and with forethought as to future needs.



SRP remains the low-cost provider in average retail electric prices throughout Arizona and the Southwest.



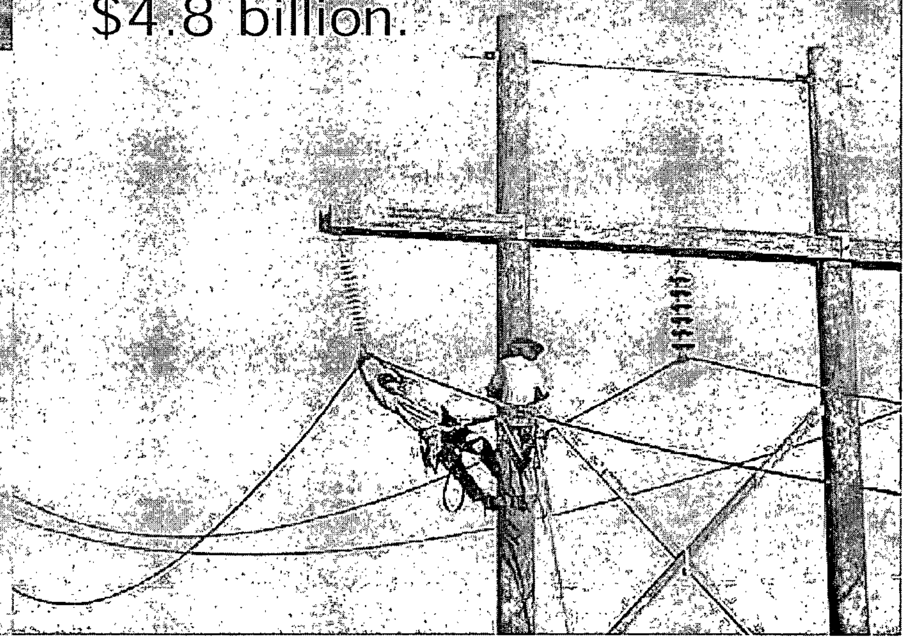
Competitively priced electricity depends largely on the availability of our low-cost, base-load coal plants. This year, two coal plants that SRP operates, Coronado Generating Station and Navajo Generating Station, provided reliability of service that rivaled the best in the industry. SRP's attention to reliability saves our customers from unnecessary supply interruptions and related expenses.

Just in time for higher summer demand, SRP's newest unit at Santan Generating Station became operational. Local generation such as the 1,225-megawatt Santan facility benefits our electric customers by increasing SRP's load-serving capability, offering voltage stability and enhancing import capabilities.

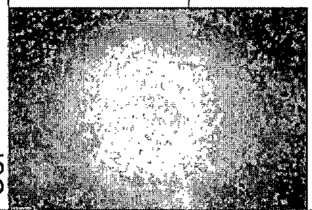
By 2010, SRP will have 1 million electric customers, requiring new generating plants, power lines, substations and transformers, and renovations and upgrades to existing assets. Our capital program for the next six years is a record $4.8 billion.

Chip-makers are extremely power sensitive – production time and financial outcomes are highly dependent on power quality.

When Intel Corp. decided to add a third fabrication plant in SRP's electric service area this past year, power quality and reliability were key factors in the decision. SRP's reputation for outstanding power quality attracts semiconductor manufacturers, data centers and customer service operations to our service area. And the rewards multiply: Intel's Arizona presence has a $2.6 billion annual impact on the state's economy.



Expanding our Portfolio

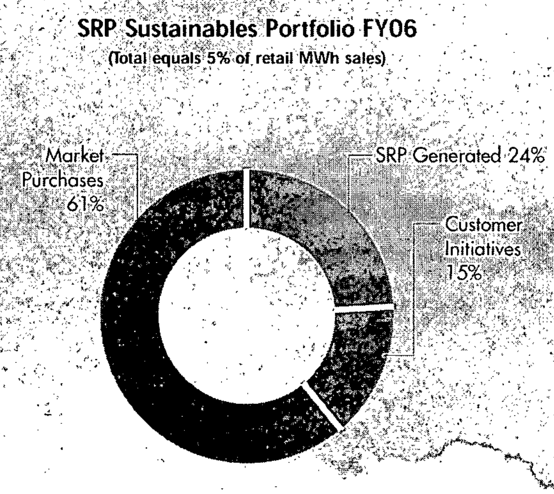


- Provide earth-friendly products and services
- Offer easy, convenient ways to save electricity
- Collaborate on renewable energy technologies

Our customers care about environmentally sound energy – and so do we.

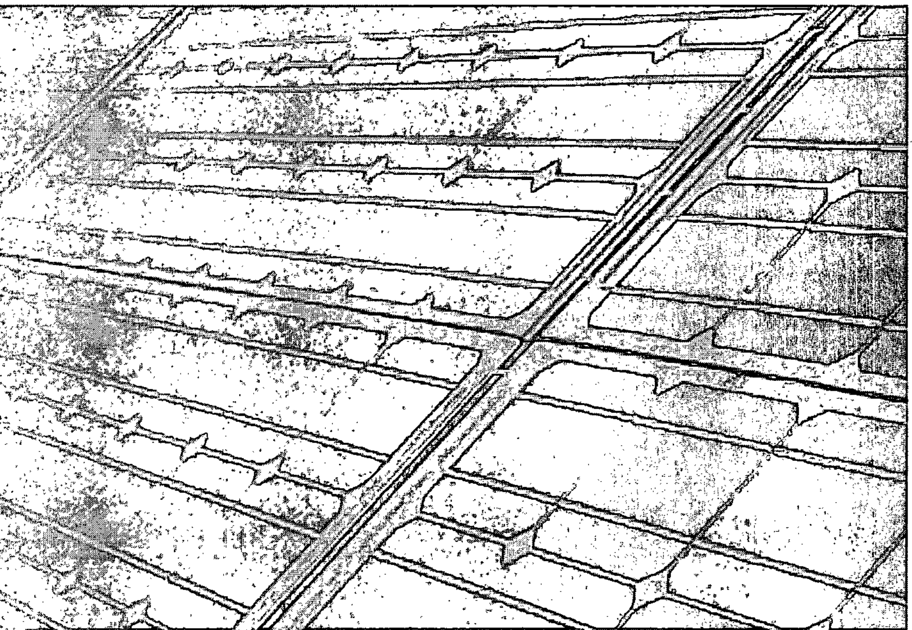
We offer energy solutions that protect the environment, through efficiency initiatives and by collaborating on the development of renewable energy technologies. We believe that sustainable energy sources are becoming more economical and more available, allowing us to increase our reliance on these resources. Accordingly, we plan to make significant investments in sustainable energy for meeting load growth over the next 20 years.

At SRP, we take pride in our history of stewardship of the Valley's environment and resources. We recognize that environmental protection, resource conservation and pollution prevention are sound business practices and add value to the services we provide.



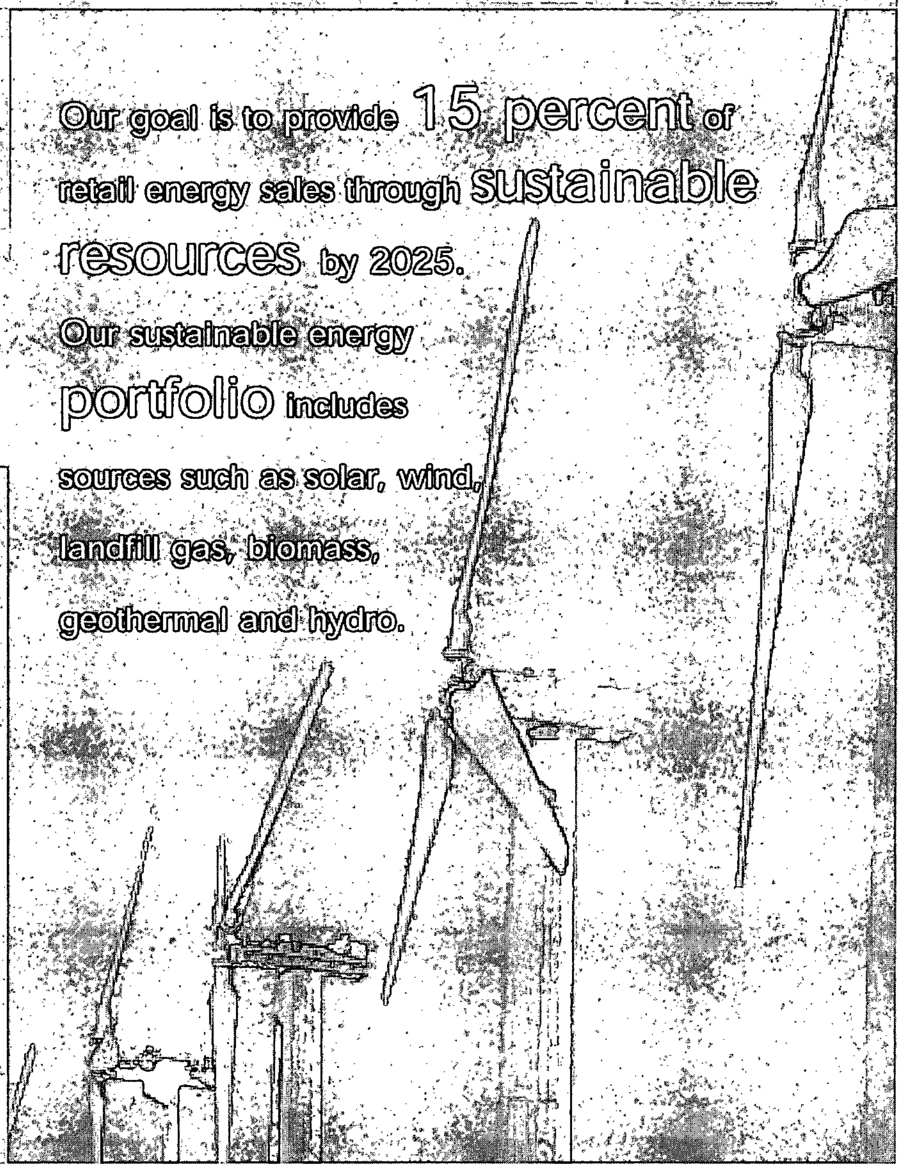
SRP's sustainable portfolio this year represented more than 1.2 million megawatt-hours of total retail sales.

We provide initiatives for customers who embrace sustainable energy technologies. This year, we expanded SRP EarthWise Solar Energy – already popular with residential customers – to commercial customers. Participants receive financial incentives for installing solar electric and solar water heating systems in their homes and businesses. EarthWise Solar Energy is one more way that we demonstrate our commitment to clean-energy technologies.



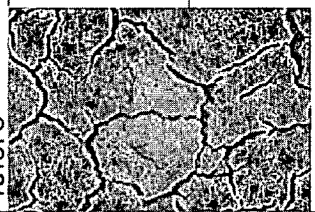
Our customers can save energy and money with SRP M-Power®, the largest "pre-pay" electric service program in North America. The convenience of buying electricity on demand and the ability to easily monitor electric use are popular features. And on average, M-Power customers use 13 percent less electricity.

In one of the hottest housing markets in the nation, SRP is helping builders find a competitive advantage through the SRP PowerWise Homes™ program. Launched this year, PowerWise Homes already has 19 participating builders with more than 12,000 new homes. These energy-smart homes are designed to reduce consumption by as much as 15 percent through measures that include highly efficient appliances and rigorous whole-house building standards.



Our goal is to provide 15 percent of retail energy sales through sustainable resources by 2025.

Our sustainable energy portfolio includes sources such as solar, wind, landfill gas, biomass, geothermal and hydro.



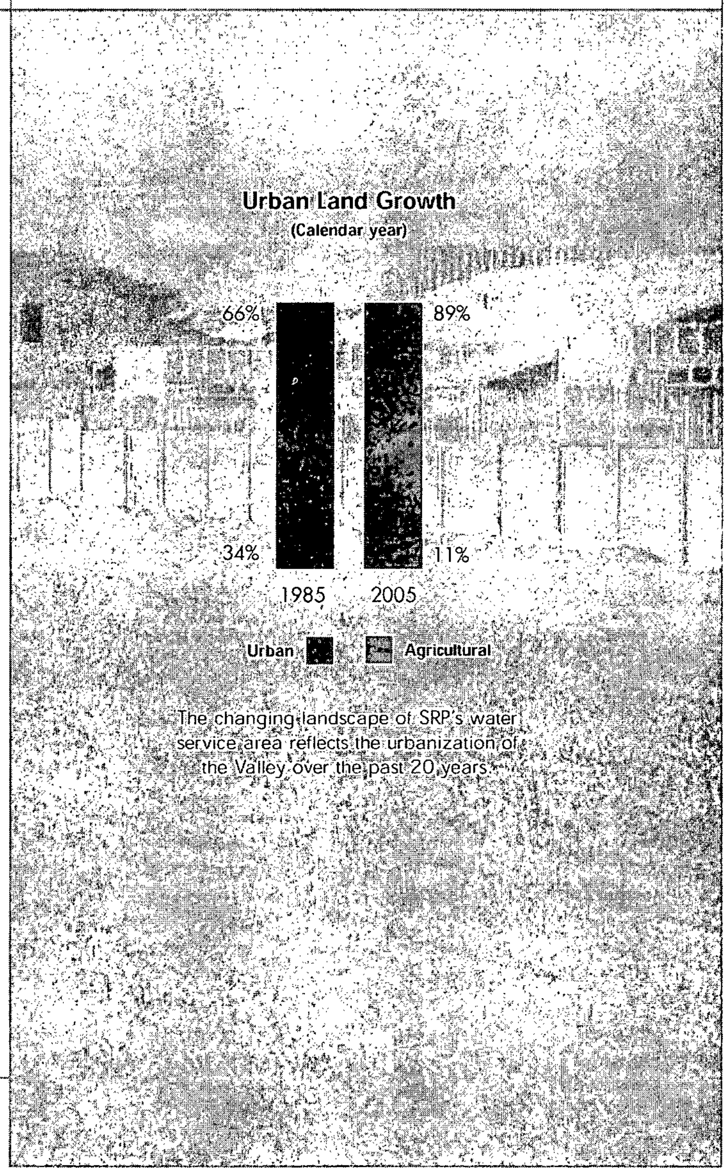
Ensuring future Supplies

- Protect sources for the long term
- Manage for prolonged drought
- Help others in efforts to conserve

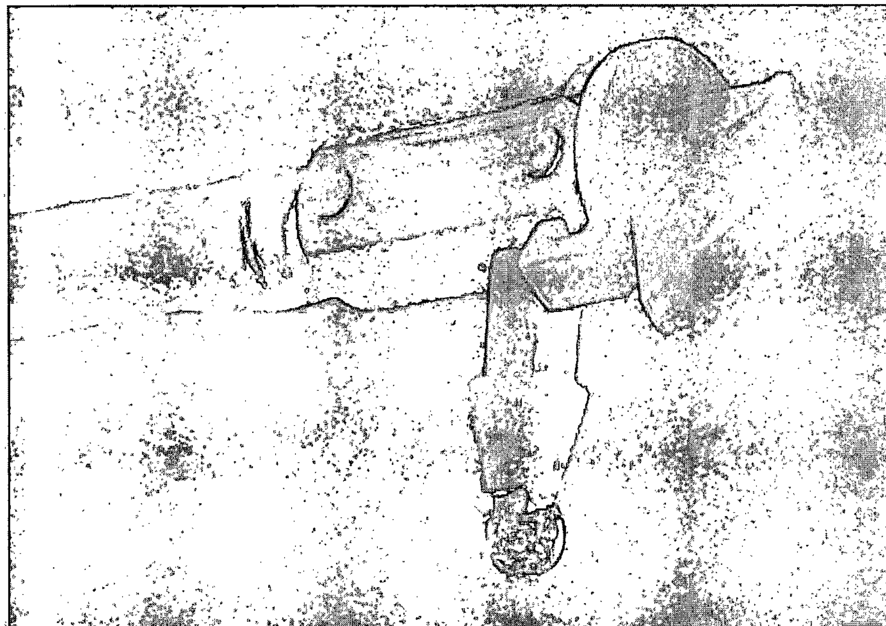
Water stewardship and its value to our water service area becomes more evident under the harsh reality of drought.

This sharper focus helps everyone to better understand the value of water management and the need to conserve water. Drought affects our water supply, our shareholders, and many other aspects of our communities and the environment. As a steward of the area's water supply for more than a century, we partner in many ways to develop new resources and to protect local water supplies.

Responsible stewardship requires that we foster a strong conservation ethic. We will continue to promote and improve water conservation practices to help ensure that the SRP water supply meets the needs of future generations.

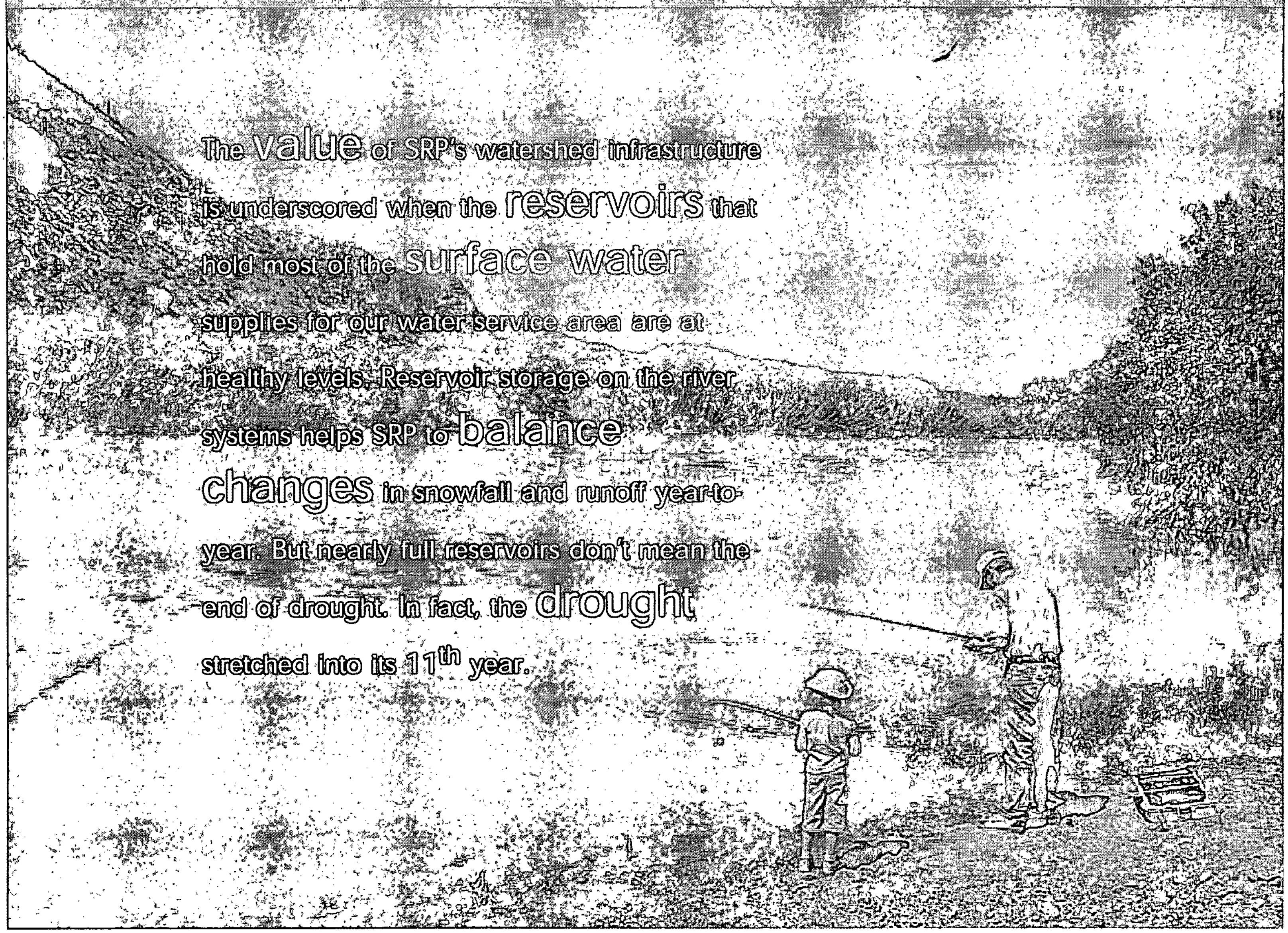


The changing landscape of SRP's water service area reflects the urbanization of the Valley over the past 20 years.



SRP's new DesertWise Homes℠ program offers incentives to builders to promote a culture of conservation by building a new generation of water-saving features into new homes. Homeowners can reduce their water use by 30 percent or more in a DesertWise Home, which includes water-smart landscaping and turf options. We have two housing subdivisions in development and expect this program to expand significantly in the years ahead.

Groundwater is a vital supplement to reservoir storage and provides another layer of drought protection. A major initiative launched this year will restore groundwater pumping capacity to peak levels of 550,000 acre-feet annually by developing new wells, enhancing existing wells and optimizing recharge projects that store surface water.



The value of SRP's watershed infrastructure is underscored when the reservoirs that hold most of the surface water supplies for our water service area are at healthy levels. Reservoir storage on the river systems helps SRP to balance changes in snowfall and runoff year-to-year. But nearly full reservoirs don't mean the end of drought. In fact, the drought stretched into its 11th year.

Serving our Communities

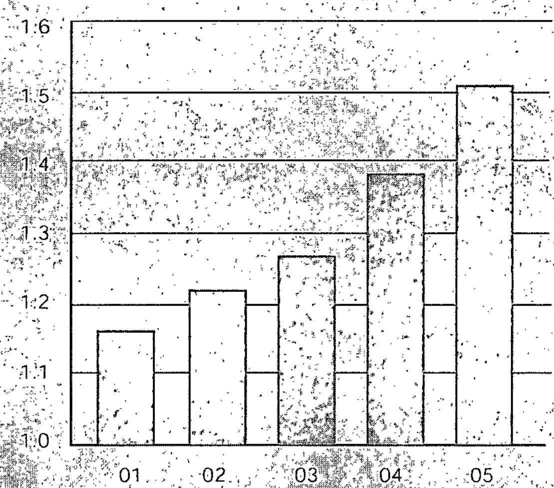
- Build upon our legacy of service
- Provide comprehensive outreach efforts
- Respect the diversity of our communities

We make it our business to make a difference in communities throughout Arizona.

Our involvement reaches deep and wide across the state – providing financial support to nonprofit organizations and programs, mobilizing our remarkable employee volunteers, and providing leadership to community organizations. Other initiatives include supporting the visual and performing arts, fulfilling our civic responsibilities and promoting community safety.

We remain committed to these activities. Our comprehensive approach, we believe, will make significant and lasting change and contribute to the well-being of people who live and work here for generations to come.

Employee Contributions to Our Communities
($Millions)



SRP employees give generously to an employee-driven annual fundraising campaign for nonprofit agencies in Arizona. Even while the number of employees remains the same, contributions each year continue to grow.

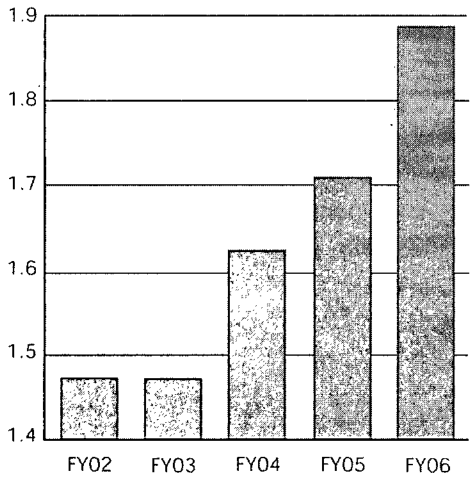
Teens and seniors came together this year to create a living history of Arizona's military veterans. With the assistance of an SRP Arizona Heritage Project grant, a Valley high school class interviewed 50 local veterans and published a book of their first-person war memories to ensure their stories are preserved for the future. SRP grants, training and scholarships for educators and students across the state comprised fully one-third of our nearly $3 million in community investments this year.

Helping underserved minority students is just one of SRP's efforts to cultivate educational excellence. In the Tempe Tutor Program, for example, SRP employee volunteers offer individualized help in reading and math to children at Arredondo Elementary School. This program returns proven results through improved scores on standardized tests.

SRP actively promotes **water safety** in our communities through collaborative efforts that include bilingual materials and outreach support for public events and schools. We also contribute to **Adopt-a-Fence**, a program with local firefighters that builds pool fencing for families who otherwise are unable to do so.

Management's Financial and Operational Summary

Electric Retail Revenues
($Billions)



Retail revenues were up nearly 28 percent in FY06 over FY02.

This section explains the general financial condition and results of operations for SRP. SRP includes the Salt River Project Agricultural Improvement and Power District (the "District"), its subsidiaries, and the Salt River Valley Water Users' Association. The results of these entities are combined for financial reporting purposes.

Overview of Business

The District owns and operates an electric system which generates, purchases, transmits and distributes electric power and energy, and provides electric service to residential, commercial, industrial and agricultural power users in a 2,900-square-mile service territory spanning portions of Maricopa, Gila and Pinal counties, plus mining loads in an adjacent 2,400-square-mile area in Gila and Pinal counties.

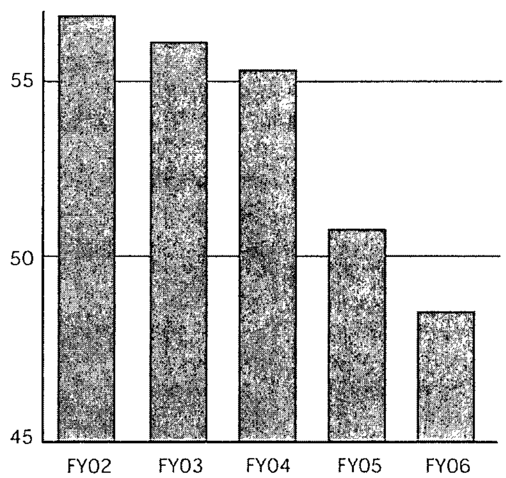
The District remains a vertically integrated organization. It is developing additional generation, transmission and distribution resources to keep pace with load growth. The District builds and acquires generation resources as needed, as well as makes short- and long-term purchases and sales of wholesale power.

For example, during the past fiscal year the District completed another new unit at Santan Generating Station, bringing that facility's total generating capacity to 1,225 megawatts (MW). Two other new units became operational in May 2005. Additionally, the District accelerated its plan to build a 400MW, coal-fired generating facility in Springerville. The new unit will be sited at Tucson Electric Power Co.'s existing Springerville Generating Station and is scheduled to be operational in late 2009.

SRP manages a system of dams and reservoirs, and has responsibility for the construction, maintenance and operation of a supply system to deliver raw water for irrigation and municipal treatment purposes. It provides the water supply for an area of about 375 square miles including portions of Phoenix, Avondale, Glendale, Mesa, Tempe, Chandler, Gilbert, Peoria, Scottsdale and Tolleson.

The District's subsidiaries include New West Energy Corp., which supports certain of the District's energy services activities outside of the District's service territory; Papago Park Center, Inc., which manages a mixed-use commercial development known as Papago Park Center located on land owned by the District adjacent to its administrative offices; SRP Captive Risk Solutions Ltd., which is a domestic captive insurer incorporated in January 2004 primarily to access property/boiler and machinery insurance coverage under the Federal Terrorism Risk

Debt Ratio
(Percent)



SRP's debt ratio in FY06 was the lowest in more than 50 years.

Insurance Act of 2002 for certified acts of terrorism; and Springerville Four LLC, which holds certain rights relating to the construction of a fourth unit at Springerville Generating Station.

Results of Operations

Net revenues for Fiscal Year 2006 ending April 30, 2006, were $415.4 million compared to $362.5 million for Fiscal Year 2005. Operating revenues were $2.5 billion for the year, compared to $2.3 billion for the previous year. Increased operating revenues were primarily the result of continued growth in SRP's retail customer base, the wholesale sales market, an increase in the Fuel and Purchase Power Adjustment Mechanism (FPPAM) in May 2005, and a retail price increase that became effective in November 2005.

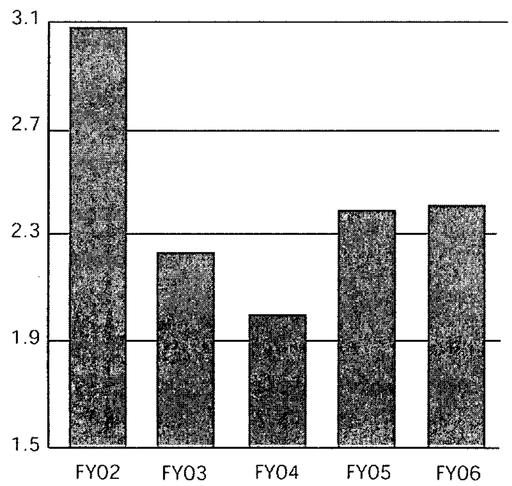
Total retail customers increased 4 percent from the previous year, with 90 percent of the increase attributed to the residential class of customers. Favorable generation unit availability combined with high wholesale-energy market prices, which are driven by high natural gas prices, resulted in a nearly 23 percent increase in wholesale revenues compared to prior year. The 1.3 percent increase in the FPPAM contributed $25.5 million to operating revenues, and the retail price increase brought in another $21.5 million.

Further impacting FY06 net revenues were realized gains on the sale of securities of $97 million. The realization of these gains resulted from selling existing investments and buying new investments within the Post-Retirement Medical and Nuclear Decommissioning funds. This is not a regularly recurring event. These gains will be retained in their respective funds, will remain committed to their stated purposes, and are not available for general corporate use.

Operating expenses were $2.1 billion for the year, compared with $1.8 billion for FY05. This change is primarily due to the high market price of natural gas, which increased both fuel and purchased-power expenses by about 42 percent and 26 percent, respectively.

In water operations, delivery revenues were $12.0 million compared to $12.8 million the previous year. Total water operating expenses were about $12.0 million less than the prior year. Improved water levels in SRP reservoirs negated the need to purchase excess Central Arizona Project water during FY06, reducing operations expenses by about $9 million from FY05.

Debt Service Coverage Ratio



Debt service coverage continued to improve this year as a result of the increase in net operating revenues, which in turn increases funds available for debt service on revenue bonds and subordinated debt.

Recently Issued Accounting Standards

FIN No. 47, *"Accounting for Conditional Asset Retirement Obligations,"* clarifies the meaning of conditional asset retirement obligations under SFAS No. 143, and provides further clarification of when sufficient information is available to provide a reasonable retirement obligation estimate. The District adopted FIN No. 47 on April 30, 2006, and has evaluated existing asset retirement obligations as provided for under this new guidance and determined that the liabilities recorded are sufficient.

Energy Risk Management Program

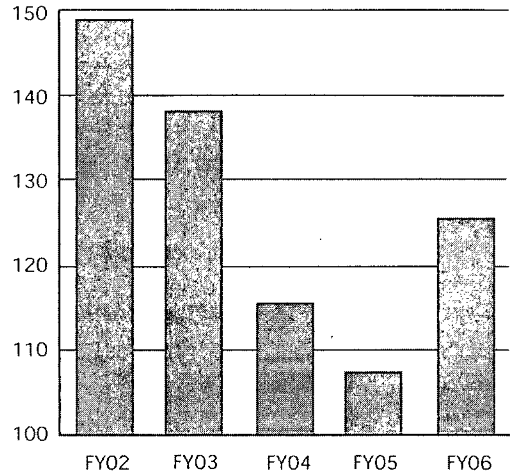
The District's mission to serve its retail customers is the cornerstone of its risk management approach. The District builds or acquires resources to serve retail customers, not the wholesale market. However, as a summer-peaking utility, there are times during the year when the District's resources and/or reserves are in excess of its retail load, thus giving rise to wholesale activity. The District has an Energy Risk Management Program to control exposure to risks inherent in retail and wholesale energy business operations by identifying, measuring, reporting and managing exposure to market, credit and operational risks. To meet the goals of the Energy Risk Management Program, the District uses various physical and financial instruments, including forward contracts, futures, swaps and options. Certain of these transactions are accounted for under SFAS No. 133, *"Accounting for Derivative Instruments and Hedging Activities."* For a detailed explanation of the effects of SFAS No. 133 on the District's financial results, see Note 3 in the accompanying notes to the Combined Financial Statements.

The Energy Risk Management Program is managed according to a policy approved by the District's Board of Directors (the Board) and is overseen by a Risk Oversight Committee. The policy covers wholesale market, credit and operational risks and includes portfolio strategies, authorizations, value-at-risk limits, stop-loss limits and duration limits. The Risk Oversight Committee is composed of senior executives. The District maintains an Energy Risk Management Department, independent of the energy marketing area, that regularly reports to the Risk Oversight Committee and to the Board. In addition, the District has established a credit reserve for its activity in wholesale markets. The District believes that its existing risk management structure is appropriate and that any exposures are adequately covered by existing reserves.

Electric Pricing

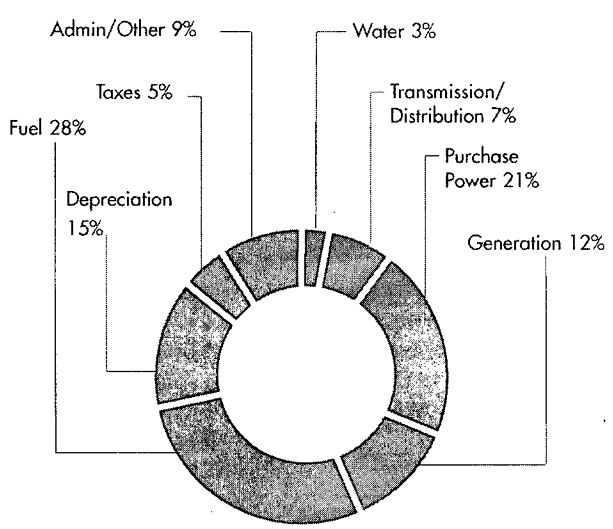
The District has a diversified customer base, with no single retail customer providing more than 1.2 percent of operating revenues. The District has implemented projects and programs geared towards enhancing customer loyalty

Net Financing Costs
($Millions)



Net financing costs this year increased due to increased interest expenses on bonds as well as a reduction to the capitalized interest deduction due to the completion of several capital projects.

O&M Dollars



About 68 percent of SRP's expenses in FY06 directly supported the power system to provide low-cost, reliable electricity.

by offering customers a range of pricing and service options. Moreover, the District is one of the low price leaders in the Southwest.

The District is a summer-peaking utility and for many years has made an effort to balance the summer-winter load relationships through seasonal price differentials. In addition, the District prices on a time-of-day basis for large commercial and industrial customers, residential customers, and certain small commercial users.

On October 3, 2005, the Board approved a 2.9 percent system average price increase effective November 1, 2005. The increase was needed to help fund a portion of SRP's Capital Improvement Program. The increase is expected to generate annual revenues of $55.8 million.

Rate Stabilization Fund

In April 2005, the District transferred $55 million into the Rate Stabilization Fund to be used in concert with the Fuel and Purchased Power Adjustment Mechanism (FPPAM) to cover fuel related expenses and to stabilize future prices related to fuel, as well as for any other purposes required or permitted by the Board's Supplemental Resolution dated September 10, 2001, authorizing an Amended and Restated Resolution Concerning Revenue Bonds, during fiscal years 2006 and 2007. A special Board meeting was held on March 30, 2006, at which the Board approved the transfer of the $55 million, plus interest earnings back to the General Fund on May 1, 2006, to help cover under-collected fuel costs, thereby reducing the need for an upward increase in the FPPAM. Management anticipates additional contributions to the Rate Stabilization Fund.

Capital Improvement Program

The Capital Improvement Program is driven by the need to expand the generation, transmission, distribution and other systems of the District to meet growing customer electricity needs and to maintain a satisfactory level of service reliability.

Fiscal Year 2006 capital spending levels were consistent with management's expectations. Generation projects, 19 percent of the year's expenditures, included completion of another unit at the Santan Generating Station and the installation of the second steam generator at the Palo Verde Nuclear Generating Station.

Expansion of the electrical distribution system to meet new growth and to replace aging underground cable accounted for 44 percent of the FY06 capital expenditures. Nearly half of distribution system spending was for new-business projects. The addition of new 69-kilovolt transmission facilities comprised an additional 9 percent of the year's capital expenditures.

COMBINED BALANCE SHEETS

As of April 30, 2006 and 2005 (Thousands)

Assets	2006	2005
UTILITY PLANT		
Plant in service –		
Electric	$ 8,311,459	$ 7,899,197
Irrigation	274,029	267,928
Common	443,533	418,716
Total plant in service	9,029,021	8,585,841
Less – Accumulated depreciation on plant in service	(4,167,664)	(3,925,661)
	4,861,357	4,660,180
Plant held for future use	3,283	3,076
Construction work in progress	309,674	414,626
Nuclear fuel, net	42,156	39,834
	5,216,470	5,117,716
OTHER PROPERTY AND INVESTMENTS		
Non-utility property and other investments	121,313	112,326
Segregated funds, net of current portion	677,652	490,518
	798,965	602,844
CURRENT ASSETS		
Cash and cash equivalents	465,947	288,429
Rate Stabilization Fund	56,892	55,000
Temporary investments	152,604	135,081
Current portion of segregated funds	79,010	131,000
Receivables, net of allowance for doubtful accounts	189,013	220,820
Fuel stocks	28,540	34,583
Materials and supplies	92,543	80,278
Other current assets	62,668	78,659
	1,127,217	1,023,850
DEFERRED CHARGES AND OTHER ASSETS	306,321	322,273
	$ 7,448,973	$ 7,066,683

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

As of April 30, 2006 and 2005 (Thousands)

Capitalization and Liabilities	2006	2005
LONG-TERM DEBT	$ 2,893,017	$ 2,727,348
ACCUMULATED NET REVENUES AND OTHER COMPREHENSIVE INCOME	3,140,862	2,714,561
TOTAL CAPITALIZATION	6,033,879	5,441,909
CURRENT LIABILITIES		
Current portion of long-term debt	131,346	274,778
Accounts payable	162,804	172,001
Accrued taxes and tax equivalents	72,757	68,974
Accrued interest	45,407	44,000
Customers' deposits	65,522	53,547
Other current liabilities	217,409	171,400
	695,245	784,700
DEFERRED CREDITS AND OTHER NON-CURRENT LIABILITIES	719,849	840,074
COMMITMENTS AND CONTINGENCIES (Notes 5,7,8,9,10 and 11)		
	$ 7,448,973	$ 7,066,683

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

COMBINED STATEMENTS OF NET REVENUES AND COMPREHENSIVE INCOME (LOSS)

For the years ended April 30, 2006 and 2005 (Thousands)

	2006	2005
OPERATING REVENUES		
Retail electric	$ 1,885,912	$ 1,709,213
Water	12,036	12,786
Other	624,022	529,724
Total operating revenues	2,521,970	2,251,723
OPERATING EXPENSES		
Power purchased	453,549	358,697
Fuel used in electric generation	605,078	425,880
Other operating expenses	461,367	429,799
Maintenance	205,193	193,489
Depreciation and amortization	313,562	302,198
Taxes and tax equivalents	100,953	105,475
Total operating expenses	2,139,702	1,815,538
Net operating revenues	382,268	436,185
OTHER INCOME (EXPENSES)		
Interest income	53,807	25,241
Gain on sale of available-for-sale securities	97,041	–
Other income (expenses), net	8,118	6,661
Total other income (expenses), net	158,966	31,902
Net revenues before financing costs	541,234	468,087
FINANCING COSTS		
Interest on bonds	117,069	118,229
Capitalized interest	(11,971)	(24,189)
Amortization of bond discount/premium and issuance expenses	(7,932)	(9,642)
Interest on other obligations	28,668	21,239
Net financing costs	125,834	105,637
NET REVENUES	415,400	362,450
OTHER COMPREHENSIVE INCOME (LOSS)	10,901	(29,279)
COMPREHENSIVE INCOME	$ 426,301	$ 333,171

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

COMBINED STATEMENTS OF CASH FLOWS

For the years ended April 30, 2006 and 2005 (Thousands)

	2006	2005
CASH FLOWS FROM OPERATING ACTIVITIES		
Net revenues	$ 415,400	$ 362,450
Adjustments to reconcile net revenues to net cash provided by operating activities:		
Depreciation, amortization and accretion	325,274	313,727
Postretirement benefits expense	51,124	43,409
Amortization of provision for loss on long-term contracts	(13,280)	(13,280)
Amortization of net bond discount/premium and issuance expenses	(7,933)	(9,642)
Amortization of spent nuclear fuel storage	1,959	1,826
Loss (gain) on sale of capital assets	(8,124)	(7,610)
Decrease (increase) in:		
Fuel stocks and materials & supplies	(6,222)	(8,729)
Receivables, including unbilled revenues, net	31,807	(43,156)
Other assets	17,320	(50,497)
Increase (decrease) in:		
Accounts payable	(9,197)	45,350
Accrued taxes and tax equivalents	3,783	1,797
Accrued interest	1,407	(1,796)
Current liabilities	57,984	23,289
Deferred credits and other non-current liabilities	(51,098)	41,657
Net cash provided by operating activities	810,204	698,795
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to utility plant, net	(432,027)	(414,530)
Proceeds from disposition of assets	10,731	23,923
Purchases of investments	(391,162)	(336,822)
Sales and maturities of securities	304,404	202,636
Investment in Rate Stabilization Fund	(1,892)	(55,000)
Proceeds from sale of available-for-sale securities	97,041	–
Decrease (increase) in segregated funds	(262,697)	(80,807)
Net cash used for investing activities	(675,602)	(660,600)
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds from issuance of revenue bonds	343,844	–
Proceeds from issuance of commercial paper	–	100,000
Repayment of long-term debt, including refundings	(312,144)	(171,334)
Other proceeds from financing activities	11,216	40,606
Net cash used for financing activities	42,916	(30,728)
NET INCREASE IN CASH AND CASH EQUIVALENTS	177,518	7,467
BALANCE AT BEGINNING OF YEAR IN CASH AND CASH EQUIVALENTS	288,429	280,962
BALANCE AT END OF YEAR IN CASH AND CASH EQUIVALENTS	$ 465,947	$ 288,429
SUPPLEMENTAL INFORMATION		
Cash paid for interest (net of capitalized interest)	$ 132,359	$ 117,075
Non-cash financing activities:		
Loss on bond retirement	$ (1,951)	$ –

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

NOTES TO COMBINED FINANCIAL STATEMENTS

April 30, 2006 and 2005

(1) Basis of Presentation:

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

In 1997, the District established a wholly-owned, taxable subsidiary, New West Energy Corporation (New West Energy), to market, at retail, energy available to the District that was surplus to the needs of its retail customers, and energy that might have been rendered surplus in Arizona by retail competition in the supply of generation. However, as a result of the turmoil in the Western energy markets, New West Energy discontinued marketing excess energy in 2001, although it may resume this activity in the future.

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

Principles of Combination – The accompanying combined financial statements reflect the combined accounts of the Association and the District (together referred to as SRP). The District's financial statements are consolidated with its four wholly-owned taxable subsidiaries: New West Energy, SRP Captive Risk Solutions, Limited (CRS), Papago Park Center, Inc. (PPC) and Springerville Four, LLC (Springerville Four). PPC is a real estate management company. CRS is a domestic captive insurer incorporated in January 2004 primarily to access property/boiler and machinery insurance coverage under the Federal Terrorism Risk Insurance Act of 2002 for certified acts of terrorism. Springerville Four is a limited liability company that holds certain rights to construct a fourth unit at Springerville Generating Station. All material inter-company transactions and balances have been eliminated.

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

(2) Significant Accounting Policies:

Basis of Accounting – The accompanying combined financial statements are presented in conformity with accounting principles generally accepted in the United States of America (GAAP) and reflect the pricing policies of the Board. The District's "regulated" operations apply Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS No. 71), while "non-regulated" operations follow GAAP for enterprises in general. Classification of regulated and non-regulated operations is determined in accordance with applicable GAAP accounting guidelines.

By virtue of SRP operating a federal reclamation project under contract, with the federal government's pre-emptive rights, asset ownership and certain approval rights, SRP is considered for financial reporting purposes to follow accounting standards as set forth by the Federal Accounting Standards Advisory Board (FASAB). Entities reporting in accordance with the standards issued by the Financial Accounting Standards Board (FASB) prior to October 19, 1999 (the date the American Institute of Certified Public Accountants (AICPA) designated the FASAB as the accounting standard setting body for entities under the federal government) are permitted to continue to report in accordance with those standards. Consequently, SRP's financial statements are reported in accordance with FASB standards.

The preparation of financial statements in compliance with GAAP requires management to make estimates and assumptions that affect the reported amounts in the financial statements and disclosures of contingencies. Actual results could differ from the estimates.

Utility Plant – Utility plant is stated at the historical cost of construction, less any impairment losses. Capitalized construction costs include labor, materials, services purchased under contract, and allocations of indirect charges for engineering, supervision, transportation and administrative expenses and capitalized interest or an allowance for funds used during construction (AFUDC). AFUDC is the estimated cost of funds used to finance plant additions and is recovered in prices through depreciation expense over the useful life of the related asset. The cost of property that is replaced, removed or abandoned, together with removal costs, less salvage, is charged to accumulated depreciation.

Composite rates of 4.51% and 4.42% were used in fiscal years 2006 and 2005 to calculate interest on funds used to finance construction work in progress, resulting in $12.0 million and $24.2 million of interest capitalized, respectively.

Depreciation expense is computed on the straight-line basis over the estimated useful lives of the various classes of plant assets. The following table reflects the District's average depreciation rates on the average cost of depreciable assets, for the fiscal years ended April 30:

	2006	2005
Average electric depreciation rate	3.51%	3.49%
Average irrigation depreciation rate	2.07%	2.44%
Average common depreciation rate	5.36%	5.52%

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

Allowance for Doubtful Accounts – The District has provided for an allowance for doubtful accounts of $12.7 million and $16.7 million as of April 30, 2006 and 2005, respectively.

Nuclear Fuel – The District amortizes the cost of nuclear fuel using the units of production method. The nuclear fuel amortization and the disposal expense are components of fuel expense. Accumulated amortization of nuclear fuel at April 30, 2006 and 2005 was $389.1 million and $373.4 million, respectively.

Asset Retirement Obligation –The District adopted Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" (SFAS No. 143), on May 1, 2003. SFAS No. 143 requires the recognition and measurement of liabilities for legal obligations associated with the retirement of tangible long-lived assets. Under the standard, these liabilities are recognized at fair value as incurred and capitalized as part of the cost of the related tangible long-lived assets. Accretion of the liabilities, due to the passage of time, is an operating expense and the capitalized cost is depreciated over the useful life of the long-lived asset. Retirement obligations associated with long-lived assets included within the scope of SFAS No. 143 are those for which a legal obligation exists under enacted laws, statutes, and written or oral contracts, including obligations arising under the doctrine of promissory estoppel.

The District adopted FASB Interpretation No. 47 (FIN 47), on April 30, 2006. FIN 47 clarifies the meaning of conditional asset retirement obligations under SFAS No. 143, and provides further clarification of when sufficient information is available to provide a reasonable retirement obligation estimate. The District has evaluated existing asset retirement obligations as provided for under this new guidance and has determined that the liabilities recorded are sufficient at this time.

The District has identified retirement obligations for the Palo Verde Nuclear Generating Station (PVNGS), Navajo Generating Station (NGS), Four Corners Generating Station (Four Corners) and certain other assets. Amounts recorded under SFAS No. 143, are subject to various assumptions and determinations, such as determining whether an obligation exists to remove assets, estimating the fair value of the costs of removal, estimating when final removal will occur, and determining the credit-adjusted, risk-free interest rates to be utilized on discounting future liabilities. Changes that may arise over time with regard to these assumptions and determinations will change amounts recorded in the future as expense for asset retirement obligations.

A summary of the asset retirement obligation activity of the District for the year ended April 30, 2006, is included below (in millions):

Balance, May 1, 2005	$	198.5
Liabilities incurred		(26.2)
Accretion expense		11.7
Balance, April 30, 2006	$	184.0

In accordance with regulations of the Nuclear Regulatory Commission, the District maintains a trust for the decommissioning of PVNGS. Decommissioning funds of $172.8 million and $150.1 million, stated at market value, as of April 30, 2006 and 2005, respectively, are held in the trust and are classified as segregated funds in the accompanying Combined Balance Sheets. Unrealized gains on decommissioning fund assets of $5.6 million and $33.5 million at April 30, 2006 and 2005, respectively, are included in deferred credits and other non-current liabilities in the accompanying Combined Balance Sheets.

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

Certain of these transactions are accounted for under Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended (SFAS No. 133). Under SFAS No. 133, derivatives are recorded in the balance sheet as either an asset or liability measured at their fair value. The standard also requires changes in the fair value of the derivative be recognized each period in current earnings or other comprehensive income depending on the purpose for using the derivative and/or its qualification, designation and effectiveness as a hedging transaction. Many of the District's contractual agreements qualify for the normal purchases and sales exception allowed under SFAS No. 133 and are not recorded at market value. (For further explanation of the effects of SFAS No. 133 on the District's financial results, see Note (3) Accounting for Derivative Instruments and Hedging Activities.)

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

Income Taxes – The District is exempt from federal and Arizona state income taxes. Accordingly, no provision for income taxes has been recorded for the District in the accompanying Combined Financial Statements.

The District has four wholly-owned taxable subsidiaries: New West Energy, CRS, PPC and Springerville Four. The tax effect of these subsidiaries' operations on the Combined Financial Statements is immaterial.

Cash Equivalents – The District treats short-term temporary cash investments with original maturities of three months or less as cash equivalents.

Rate Stabilization Fund – In April 2005, the District transferred $55 million into the Rate Stabilization Fund (RSF) to be used in concert with the Fuel and Purchased Power Adjustment Mechanism (FPPAM) to cover fuel related expenses and to stabilize future prices related to fuel, as well as for any other purposes required or permitted by the Board's Supplemental Resolution dated September 10, 2001 authorizing an Amended and Restated Resolution Concerning Revenue Bonds (Bond Resolution), during fiscal years 2006 and 2007. A special Board meeting was held on March 30, 2006, at which the Board approved the transfer of the $55 million, plus interest earnings back to the General Fund on May 1, 2006 to help cover undercollected fuel costs, thereby reducing the need for an upward increase in the FPPAM. (See Note (9) Regulatory Issues, The Changing Regulatory Environment, for additional information on the FPPAM.)

Revenue Recognition – The District recognizes revenue when billed and accrues estimated revenue for electricity delivered to customers that has not yet been billed. Other operating revenue consists primarily of revenue from marketing and trading electricity.

Materials and Supplies, and Fuel Stocks – Materials and supplies are stated at lower of market or average cost. Fuel stocks are stated at lower of market or weighted average cost.

Reclassifications – For comparative purposes, certain prior year amounts have been reclassified to conform to the current year presentation. The reclassifications had no impact on net revenues or cash flows.

Recently Issued Accounting Standards – FASB has issued the following Statement of Financial Accounting Standards (SFAS), Staff Positions (FSP), and Interpretations (FIN) that may have financial impacts on the District:

FIN No. 47, "Accounting for Conditional Asset Retirement Obligations," clarifies the meaning of conditional asset retirement obligations under SFAS No. 143, and provides further clarification of when sufficient information is available to provide a reasonable retirement obligation estimate. The District adopted FIN No. 47 on April 30, 2006, and has evaluated existing asset retirement obligations as provided for under this new guidance and determined that the liabilities recorded are sufficient.

(3) Accounting for Derivative Instruments and Hedging Activities:

The District follows SFAS No. 133, as amended, which requires that entities recognize all derivatives as either assets or liabilities in the balance sheet and measure those instruments at fair value. Changes in the fair value of derivative financial instruments are either recognized periodically in net revenues or accumulated net revenues (as a component of other comprehensive income), depending on whether or not the derivative meets specific hedge accounting criteria. The criteria include a requirement for hedge effectiveness, which is measured based on the relative changes in fair value between the derivative contract and the hedged item over time. Changes in the fair value resulting from ineffectiveness are recognized immediately in net revenues.

The District enters into contracts for electricity, natural gas and other energy commodities to meet the expected needs of its retail customers. The District sells excess capacity during periods when it is not needed to meet retail requirements. The District's energy risk-management program uses various physical and financial contracts to hedge exposures to fluctuating commodity prices. The District examines contracts at inception to determine the appropriate accounting treatment. If a contract does not meet the derivative criteria, or if it qualifies for the SFAS No. 133 normal purchases and sales scope exception, the District accounts for the contract using settlement accounting (costs and revenues are recorded when physical delivery occurs). Contracts that qualify as a derivative but do not meet the SFAS No. 133 normal purchases and sales scope exception are further examined by the District to determine if they qualify for cash flow hedge accounting. If a contract does not meet the hedging criteria in SFAS No. 133, the District recognizes the changes in the fair value of the derivative instrument in net revenues each period (mark-to-market). If the contract does qualify for hedge accounting, changes in the fair value are recorded as assets or liabilities and as a component of other comprehensive income.

The District formally documents all relationships between hedging instruments and hedged items, as well as its risk-management objective and strategy for undertaking various hedge transactions. This process includes linking all derivatives to the forecasted transactions. The District also formally assesses (both at the hedge's inception and on an ongoing basis) whether the derivatives used in hedging transactions have been effective in offsetting changes in cash flow of hedged items and whether those derivatives may be expected to remain effective in future periods. When it is determined that a derivative is not (or has ceased to be) effective as a hedge, the District discontinues hedge accounting prospectively, as discussed below.

The District discontinues hedge accounting when: (1) it determines that the derivative is no longer effective in offsetting changes in cash flows of a hedged item; (2) the derivative expires or is sold, terminated or exercised; (3) it is no longer probable that the forecasted transaction will occur; or (4) management determines that designating the derivative as a hedging instrument is no longer appropriate.

When the District discontinues hedge accounting because it is no longer probable that the forecasted transaction will occur in the originally expected period, the gain or loss on the derivative is reclassified into net revenues. If the derivative remains outstanding, the District will carry the derivative at its fair value in the Combined Balance Sheets, recognizing changes in the fair value in current-period net revenues.

As of April 30, 2006 and 2005, the valuation of the District's energy risk-management contracts resulted in an increase (decrease) in electric revenues of $9.0 million and ($4.9) million, respectively, and an increase (decrease) in fuel expenses of $33.5 million and ($40.1) million, respectively. The impact to combined net revenues for fiscal years 2006 and 2005 was an unrealized gain (loss) of ($24.5) million and $35.2 million, respectively. Accumulated net revenues and other comprehensive income (as a component of other comprehensive income) were unchanged as of April 30, 2006 and April 30, 2005. The following table summarizes the District's derivative-related assets and liabilities at April 30 (in thousands):

	2006	2005
Other current assets	$ 45,901	$ 65,485
Deferred charges and other assets	50,323	65,915
Other current liabilities	(63,937)	(37,900)
Deferred credits and other non-current liabilities	(38,976)	(82,398)
Net asset	$ (6,689)	$ 11,102

The electric industry engages in an activity called "book-out," under which some energy purchases are netted against sales, and power does not actually flow in settlement of the contract. As a result of these transactions, the District nets the impacts of these financially settled contracts, which reduced revenues and purchase power expense by $290.5 million and $142.7 million for fiscal years 2006 and 2005, respectively, but which did not impact net revenues or cash flows.

(4) Accumulated Net Revenues and Other Comprehensive Income:

The following table summarizes accumulated net revenues and other comprehensive income (in thousands):

	Accumulated Net Revenues	Accumulated Other Comprehensive Income (Loss)	Accumulated Net Revenues And Other Comprehensive Income
BALANCE, April 30, 2004	$ 2,424,476	$ (43,086)	$ 2,381,390
Net revenues	362,450	–	362,450
Minimum pension liability	–	(35,300)	(35,300)
Net unrealized gain on available-for-sale securities	–	6,021	6,021
BALANCE, April 30, 2005	$ 2,786,926	$ (72,365)	$ 2,714,561
Net revenues	415,400	–	415,400
Minimum pension liability	–	41,400	41,400
Reclassification of realized gain to income	–	(55,162)	(55,162)
Net unrealized gain on available-for-sale securities	–	24,663	24,663
BALANCE, April 30, 2006	$ 3,202,326	$ (61,464)	$ 3,140,862

The majority of net unrealized gain on available-for-sale securities originates from segregated fund investments. Net unrealized gain on available-for-sale securities consists of gross unrealized gain on equity funds of $28.7 million and $6.0 million, and gross unrealized gain (loss) on debt funds of ($4.1) million and ($0.02) million, at April 30, 2006 and 2005, respectively. Accumulated Other Comprehensive Income (Loss) consists of minimum pension liability of ($73,300) and ($114,700), and net unrealized gain on available-for-sale securities of $11,836 and $42,335, at April 30, 2006 and 2005, respectively.

(5) Long-Term Debt:

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

	Interest Rate	2006	2005
Revenue bonds (mature through 2035)	4.0 - 6.0%	$ 2,213,584	$ 2,204,217
Unamortized bond (discount) premium		53,099	40,229
Total revenue bonds outstanding		2,266,683	2,244,446
Finance lease	2.0 - 5.3%	282,680	282,680
Commercial paper	3.1 - 3.8%	475,000	475,000
Total long term debt		3,024,363	3,002,126
Less current portion		(131,346)	(274,778)
Total long-term debt, net of current portion		$ 2,893,017	$ 2,727,348

The annual maturities of long-term debt (excluding commercial paper and unamortized bond discount/premium) as of April 30, 2006, due in fiscal years ending April 30, are as follows (in thousands):

Calendar Year	Revenue Bonds	Finance Lease
2006	$ –	$ 16,300
2007	115,046	16,015
2008	136,023	17,780
2009	153,205	16,790
2010	115,855	19,950
2011	108,480	17,455
Thereafter	1,584,975	178,390
	$ 2,213,584	$ 282,680

Revenue Bonds – Revenue bonds are secured by a pledge of, and a lien on, the revenues of the electric system, after deducting operating expenses, as defined in the Bond Resolution. Under the terms of the amended and restated Bond Resolution, effective in January 2003, the District is no longer required to make monthly deposits to an externally trusteed debt service fund for the payment of future principal and interest. However, the District is continuing to make debt service deposits to a non-trusteed segregated fund. Included in segregated funds in the accompanying Combined Balance Sheets are $146.7 million and $198.7 million of debt service related funds as of April 30, 2006 and 2005, respectively.

The District has $49.9 million of mini-revenue bonds outstanding, which are redeemable at the option of the bondholder under certain circumstances. Based on historical redemptions made on these bonds, management believes there are sufficient funds available to cover potential redemptions in any year.

The debt service coverage ratio, as defined in the Bond Resolution, is used by bond rating agencies to help evaluate the financial viability of the District. For the years ended April 30, 2006 and 2005, the debt service coverage ratio was 2.42 and 2.39, respectively.

Interest and the amortization of the bond discount, premium and issue expense on the various issues results in an effective rate of 4.95% over the remaining term of the bonds.

The District has authorization to issue additional Electric System Revenue Bonds totaling $722 million principal amount and Electric System Refunding Revenue Bonds totaling $2.9 billion principal amount.

In September 2005, the District issued $327.1 million Electric System Revenue Bonds. About $301.9 million of the net proceeds from these bonds are being used to fund distribution capital requirements and $43.7 million of the net proceeds were used to retire outstanding revenue bonds with an aggregate par amount of $41.0 million. The bond retirement is expected to reduce total debt payments over the life of the bonds by $5.2 million and is expected to result in present value savings of approximately $2.6 million. This transaction resulted in a net loss for accounting purposes of approximately $2.0 million, which was deferred and will be amortized over the life of the bonds to be refunded.

Finance Lease – In December 2003, the District entered into a lease-purchase agreement (Desert Basin Lease-Purchase Agreement) with Desert Basin Independent Trust (DBIT) to finance the acquisition of the Desert Basin Generating Station (Desert Basin) located in Central Arizona. In a concurrent transaction, $282.7 million in fixed-rate Certificates of Participation (COPs) were issued pursuant to a Trust Indenture, between Wilmington Trust Company, as trustee, and DBIT, to fund the acquisition of Desert Basin and other electric system assets of the District. Investors in the COPs obtained an interest in the lease payments made by the District to DBIT under the Desert Basin Lease-Purchase Agreement. Due to the nature of the Desert Basin Lease-Purchase Agreement, the District has recorded a lease-finance liability to DBIT with the same terms as the COPs.

In connection with the issuance of the COPs, the District entered into an interest rate swap transaction with Morgan Stanley Capital Services. This transaction consisted of a 6-year, $75 million fixed-to-floating swap (annual $25 million notional maturities expiring on December 1, 2007 through 2009, respectively) versus the Bond Market Association (BMA) Municipal Index. The fixed-receiver rate on the swap is 3.001%. Through the swap, the District was able to create synthetic variable rate debt and take advantage of the relationship between intermediate-term, tax-exempt borrowing costs and BMA-based, fixed-receiver swap rates. In addition, the swap to variable rate also enables the District to increase its short-term, variable rate debt portfolio. The interest rate swap is accounted for as a derivative and qualifies for hedge accounting. (For further explanation of the effects of SFAS No. 133 on the District's financial results see Note (3) Accounting for Derivative Instruments and Hedging Activities.)

Commercial Paper – The District has outstanding $475.0 million of commercial paper consisting of $375.0 million Series B Commercial Paper and $100.0 million Series C Commercial Paper. The issues have an average weighted interest rate to the District of 3.34%.

The commercial paper matures not more than 270 days from the date of issuance and is an unsecured obligation of the District. The District has the ability to refinance the outstanding commercial paper on a long-term basis in connection with its revolving line of credit that supports the commercial paper and is available through December 7, 2009. As such, the District has classified the commercial paper as long-term debt in the Combined Balance Sheets as of April 30, 2006.

While the revolving credit agreement contains covenants that could prohibit borrowing under certain conditions, management believes financing would be available. The District has never borrowed under the agreement and management does not expect to do so in the future. Alternative sources of funds to support the commercial paper program include existing funds on hand or the issuance of alternative debt, such as revenue bonds.

Line-of-Credit Agreements – The District has a $475.0 million revolving line-of-credit agreement that supports the $475.0 million commercial paper program. The agreement has various covenants, with which management believes the District was in compliance at April 30, 2006.

(6) Fair Value of Financial Instruments:

The following methods and assumptions were used to estimate the fair value of each class of financial instruments identified in the following items in the accompanying Combined Balance Sheets.

Investments in Marketable Securities – The District invests in U.S. government obligations, certificates of deposit and other marketable investments. Such investments are classified as other investments, segregated funds, cash and cash equivalents or temporary investments in the accompanying Combined Balance Sheets depending on the purpose and duration of the investment. The fair value of marketable securities with original maturities greater than one year is based on published market data. The carrying amount of marketable securities with original maturities of one year or less approximates their fair value because of their short-term maturities.

Long-Term Debt – The fair value of the District's revenue bonds, including the current portion, was estimated by using pricing scales from independent sources. The carrying amount of commercial paper approximates the fair value because of its short-term maturity.

Other Current Assets and Liabilities – The carrying amounts of receivables, accounts payable, customers' deposits and other current liabilities in the accompanying Combined Balance Sheets approximate fair value because of their short-term maturities.

The estimated carrying amounts and fair values of the District's financial instruments, at April 30, are as follows (in thousands):

	2006		2005	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Investments in marketable securities:				
Other investments	$ 45,000	$ 44,490	$ 35,765	$ 35,406
Segregated funds	$ 756,662	$ 755,957	$ 621,518	$ 622,100
Rate Stabilization Fund	$ 56,892	$ 56,892	$ 55,000	$ 55,000
Temporary investments	$ 152,604	$ 152,217	$ 135,081	$ 134,822
Long-term debt	$ 3,024,363	$ 3,054,834	$ 3,002,126	$ 3,143,934

Accounting for Debt and Equity Securities – The District's investments in debt securities are reported at amortized cost if the intent is to hold the security to maturity. At April 30, 2006, the District's investments in debt securities have maturity dates ranging from May 2, 2006 to February 28, 2012. Other debt and equity securities are reported at market, with unrealized gains or losses included as a separate component of Accumulated Net Revenues and Other Comprehensive Income. The District's investments in debt and equity securities are included in temporary investments, segregated funds and non-utility property and other investments in the accompanying Combined Balance Sheets.

(7) Employee Benefit Plans and Incentive Programs:

Defined Benefit Pension Plan and Other Postretirement Benefits – SRP's Employees' Retirement Plan (the Plan) covers substantially all employees. The Plan is funded entirely from SRP contributions and the income earned on invested Plan assets. The District made a contribution of $60.0 million and $75.0 million in fiscal years 2006 and 2005, respectively.

SRP provides a non-contributory defined benefit medical plan for retired employees and their eligible dependents (contributory for employees hired January 1, 2000 or later) and a non-contributory defined benefit life insurance plan for retired employees. Employees are eligible for coverage if they retire at age 65 or older with at least five years of vested service under the Plan (ten years for those hired January 1, 2000 or later), or any time after attainment of age 55 with a minimum of ten years of vested service under the Plan (20 years for those hired January 1, 2000 or later). The funding policy is discretionary and is based on actuarial determinations. The unrecognized transition obligation is being amortized over 20 years, beginning in 1994.

The following tables outline changes in benefit obligations, Plan assets, the funded status of the plans and amounts included in the Combined Financial Statements as of April 30, based on January 31 valuation dates (in thousands):

	Pension Benefits		Postretirement Benefits	
	2006	2005	2006	2005
Change in benefits obligation:				
Benefit obligation at beginning of year	$ 1,017,000	$ 889,000	$ 442,200	$ 392,700
Service cost	31,800	27,100	11,300	8,800
Interest cost	57,500	54,600	25,100	22,500
Amendments	–	–	200	–
Actuarial loss	24,500	82,200	45,600	30,400
Benefits paid	(34,100)	(35,900)	(13,700)	(12,200)
Benefit obligations at end of year	$ 1,096,700	$ 1,017,000	$ 510,700	$ 442,200

	Pension Benefits		Postretirement Benefits	
	2006	**2005**	**2006**	**2005**
Change in Plan assets:				
Fair value of Plan assets at beginning of year	$ 795,300	$ 670,000	$ –	$ –
Actual return on Plan assets	107,700	76,200	–	–
Employer contributions	60,000	85,000	13,600	12,200
Benefits paid	(34,100)	(35,900)	(13,600)	(12,200)
Fair value of Plan assets at end of year	$ 928,900	$ 795,300	$ –	$ –
Funded status	$ (167,800)	$ (221,700)	$ (510,700)	$ (442,200)
Unrecognized transition obligation	–	–	21,800	32,900
Unrecognized net actuarial loss	239,200	270,200	219,200	184,600
Unrecognized prior service cost	18,000	20,300	7,600	500
Post January 31 contributions	–	–	3,800	3,100
Net asset (liability) recognized	$ 89,400	$ 68,800	$ (258,300)	$ (221,100)
Amounts recognized in Combined Balance Sheets:				
Prepaid benefit cost	$ 89,400	$ 68,800	$ –	$ –
Additional minimum liability	(91,300)	(135,000)	–	–
Net additional minimum liability	(1,900)	(66,200)	–	–
Accrued benefit liability	–	–	(258,300)	(221,100)
Intangible asset	18,000	20,300	–	–
Accumulated other comprehensive income	73,300	114,700	–	–
Net asset (liability) recognized	$ 89,400	$ 68,800	$ (258,300)	$ (221,100)

The following table outlines the projected benefit obligation and accumulated benefit obligation in excess of Plan assets as of April 30, based on January 31 valuation dates (in thousands):

	2006	**2005**
Projected benefit obligation	$ 1,096,700	$ 1,017,000
Accumulated benefit obligation	$ 930,800	$ 861,500
Fair value of Plan assets	$ 928,900	$ 795,300

The District internally funds its other postretirement benefits obligation. At April 30, 2006 and 2005, $339.5 million and $253.9 million of segregated funds, respectively, were designated for this purpose.

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

	Pension Benefits		Postretirement Benefits	
	2006	2005	2006	2005
Discount rate	5.75%	5.75%	5.75%	5.75%
Rate of compensation increase	4.0%	4.0%	4.0%	4.0%

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

	Pension Benefits		Postretirement Benefits	
	2006	2005	2006	2005
Discount rate	5.75%	6.25%	5.75%	6.25%
Expected return on Plan assets	8.25%	7.75%	N/A	N/A
Rate of compensation increase	4.0%	4.0%	4.0%	4.0%

For employees who retire at age 65 or younger, for measurement purposes, a 9% annual increase before attainment of age 65 and an 11% annual increase on and after attainment of age 65 in per capita costs of health care benefits were assumed during 2006; these rates were assumed to decrease uniformly until equaling 5.0% in all future years.

Components of net periodic benefit (gain) costs for the years ended April 30, are as follows (in thousands):

	Pension Benefits		Postretirement Benefits	
	2006	2005	2006	2005
Service cost	$ 31,800	$ 27,100	$ 11,300	$ 8,800
Interest cost	57,500	54,600	25,100	22,500
Expected return on Plan assets	(66,400)	(57,000)	–	–
Amortization of transition obligation	–	–	4,100	4,100
Recognized net actuarial loss	14,200	7,600	11,000	7,800
Amortization of prior service cost	2,300	2,500	100	100
Net periodic benefit cost	$ 39,400	$ 34,800	$ 51,600	$ 43,300

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

	One Percentage-Point Increase	One Percentage-Point Decrease
Effect on total service cost and interest cost components	$ 6,000	$ (5,300)
Effect on postretirement benefit obligation	$ 75,600	$ (67,000)

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

The Plan's weighted-average asset allocations at April 30, based on January 31 valuations, are as follows:

	Target Allocations	2006	2005
Equity securities	65.0%	66.0%	65.8%
Debt securities	25.0%	25.3%	25.2%
Real estate	10.0%	8.7%	9.0%
Total	100.0%	100.0%	100.0%

The investment policy allows for a tolerance range of plus or minus 5% from the stated target asset allocation.

Long-Term Rate of Return – The expected return on Plan assets is based on a review of the Plan asset allocations and consultations with a third-party investment consultant and the Plan actuary, considering market and economic indicators, historical market returns, correlations and volatility, and recent professional or academic research. As history has demonstrated, markets may decline and increase dramatically; however, the expected rate of return on the Plan assets is reasonable given its asset allocation in relation to historical and expected future performance.

Employer Contributions – The District expects to contribute $70 million to the Plan over the next valuation period.

Benefits Payments – The District expects to pay benefits in the amounts as follows (in thousands):

2007	$	37,820
2008	$	40,271
2009	$	43,573
2010	$	47,383
2011	$	51,154
2012 through 2016	$	315,556

Defined Contribution Plan – SRP's Employees' 401(k) Plan (the 401(k) Plan) covers substantially all employees. The 401(k) Plan receives employee pre-tax and post-tax contributions and partial employer matching contributions. Employer matching contributions to the 401(k) Plan were $11.2 million and $9.7 million during fiscal years 2006 and 2005, respectively.

Employee Incentive Compensation Program – SRP has an incentive compensation program covering substantially all regular employees. The incentive compensation amount is based on achievement of pre-established targets. An accrual of $28.6 million and $26.4 million for fiscal years ended April 30, 2006 and 2005, respectively, is included in other current liabilities in the accompanying Combined Balance Sheets. This liability is stated net of receivables from participants in jointly owned electric plants of $2.7 million and $2.7 million at April 30, 2006 and 2005, respectively.

(8) Interests in Jointly Owned Electric Utility Plants:

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

The following table reflects the District's ownership interest in jointly owned electric utility plants as of April 30, 2006 (in thousands):

Generating Station	Ownership Share	Plant in Service	Accumulated Depreciation	Construction Work In Progress
Four Corners (NM) (Units 4 & 5)	10.00%	$ 105,554	$ (94,064)	$ 4,694
Mohave (NV) (Units 1 & 2)	20.00%	131,804	(129,263)	-
NGS (AZ) (Units 1, 2 & 3)	21.70%	348,066	(271,056)	10,658
Hayden (CO) (Unit 2)	50.00%	116,089	(84,639)	1,059
Craig (CO) (Units 1 & 2)	29.00%	267,561	(163,919)	1,631
PVNGS (AZ) (Units 1, 2 & 3)	17.49%	1,252,081	(877,354)	28,714
		$ 2,221,155	$ (1,620,295)	$ 46,756

The Mohave Generating Station (Mohave) ceased operations on December 31, 2005, pending installation of new environmental controls and resolution of other operating issues. (See Note (9), Regulatory Issues, Mohave Generating Station, for a discussion of matters pertaining to Mohave.) There remains approximately $2.5 million in net plant value at Mohave for the Switchyard and Transmission Line still used to route power to other inter-tied systems.

(9) Regulatory Issues:

Fundamental Changes in the Electric Utility Industry – The District historically operated in a highly regulated environment in which it had an obligation to deliver electric service to customers within its service area. In 1998, the Arizona Electric Power Competition Act (the Act) authorized competition in the retail sales of electric generation, recovery of stranded costs, and competition in billing, metering and meter reading.

Similarly, in 1999, the Arizona Corporation Commission (the Commission), which regulates public service corporations, approved final rules for retail electric competition.

While retail competition was available to all customers by 2001, there were only a few customers who chose an alternative energy provider. Those customers have since returned to their incumbent utilities. At this time, there is no active retail competition within the District's service territory or, to the knowledge of the District, within the State of Arizona.

As provided for in the Act, the District assessed a temporary surcharge on electric distribution service prices to pay for all or a portion of unmitigated stranded costs of electric generation service incurred as a direct result of the onset of competition. The Act required that such costs, in order to be recovered, must have been incurred to serve customers in Arizona before December 26, 1996, and that the surcharge must not have caused prices to exceed the prices that were in effect on December 30, 1998. Effective June 1, 2004, the District ceased collection of this surcharge.

In January 2004, the Arizona Court of Appeals found numerous provisions of the Commission's retail electric competition rules to be invalid. Specifically, the court concluded that the Certificates of Convenience and Necessity awarded by the Commission to fifteen competitive electric service providers were invalid due to the Commission's failure to determine the fair value of the utility's Arizona property in setting rates. Other rules affected included the requirement to create an independent scheduling administrator and billing and collection practices. At this time, the Commission has taken no action to modify its electric competition rules to address the ruling of the Court of Appeals.

In 1996, the Federal Energy Regulatory Commission (FERC), which regulates the wholesale electric utility industry under the authority of various statutes, issued Orders 888 and 889 requiring transmitting "public utilities" (as defined in the Federal Power Act), to provide nondiscriminatory transmission services to entities seeking to effect wholesale power transactions, and to grant equal access to information concerning the pricing and availability of transmission services. The District is not a public utility under the Federal Power Act but historically has complied with these requirements voluntarily. The Energy Policy Act of 2005 (the "Energy Policy Act") expanded FERC jurisdiction by granting FERC discretionary authority to regulate the non-rate terms and conditions, and to a lesser extent, rates, under which unregulated transmitting utilities (including the District) provide wholesale transmission services. The Energy Policy Act explicitly prohibits FERC from requiring unregulated transmitting utilities to take actions that would violate a private activity bond rule. The extent to which FERC will exercise its authority over unregulated transmitting utilities is unknown at this time. However, FERC has initiated a number of regulatory actions that could affect the District's transmission and wholesale sales activities including a Notice of Proposed Rule-Making to revise and update Order 888. The District is monitoring these actions but does not expect them to result in significant adverse impacts on its operations.

The Changing Regulatory Environment – The District has fully opened its service area to competition in generation and billing, metering and meter reading. The District's electric distribution area remains regulated by its Board, and the District will not provide distribution services in the distribution areas of other utilities.

The District's price plans have been unbundled since 1999. In May 2002, the District implemented a Fuel & Purchased Power Adjustment Mechanism (FPPAM) to allow for semi-annual rate adjustments to recover increases in actual fuel costs. The District has had several increases in the price of fuel and purchased power since the FPPAM was implemented. (See Note (2) Significant Accounting Policies, Rate Stabilization Fund, for additional information.) In June 2004, the District introduced a Transmission Cost Adjustment Factor (TCAF) to recover costs the District would incur if the District were required to participate in regional transmission organizations. To date, no costs have been incurred or recovered through the TCAF.

On October 3, 2005 the District Board approved a 2.9% system average price increase beginning November 1, 2005. The increase was needed to help fund a portion of the Capital Improvement Program. The increase is expected to generate annual revenues of $55.8 million.

Through a surcharge to the District's transmission and distribution customers, the District recovers the costs of programs benefiting the general public, such as discounted rates for the elderly or impoverished, efficiency programs, demand-side management measures, renewable energy programs, economic development, research and development and nuclear decommissioning, including the cost of spent fuel storage. In its recent pricing approval, the Board approved additional funding for renewable energy programs, energy efficiency and energy conservation. These surcharges continue to be separately identified and included in the District's price plans for the regulated portion of its operations.

Regulatory Accounting – The District accounts for the financial effects of the regulated portion of its operations in accordance with the provisions of SFAS No. 71, which requires cost-based, rate-regulated utilities to reflect the impacts of regulatory decisions in their financial statements.

Regulatory assets for spent nuclear fuel storage are amortized over the life of the nuclear plant. Bond defeasance regulatory assets are amortized over different periods, beginning in fiscal year 1997 and ending in fiscal year 2031. Regulatory assets are included in deferred charges and other assets on the accompanying Combined Balance Sheets.

Mohave Generating Station – The District and the other Participants in Mohave entered into a settlement with the Sierra Club, the Grand Canyon Trust, and the National Parks Conservation Association, that required the installation of certain pollution abatement equipment by the end of 2005 to continue operating as a coal-fired electric generating facility. (See Note (11) Contingencies, Air Quality, for additional information on air quality issues.) In addition, the initial term of the agreement with Peabody Western Coal Company (Peabody) to supply coal to Mohave expired at the end of 2005 and the Hopi Tribe demanded that the pumping of water from the Navajo Aquifer for the slurry pipeline serving Mohave cease. The Mohave Participants have refused to commit to install pollution abatement equipment without reasonable assurance that water will be available to enable the delivery of coal to the plant. Consequently, the plant suspended operations at the end of 2005. The Mohave Participants, the Navajo Nation, the Hopi Tribe and Peabody have been participating in mediation for the right to use an alternative source of water for the mine and the slurry pipeline and to resolve other pending issues. However, Southern California Edison Company (SCE), operating agent for Mohave, has advised the District that it does not intend to proceed with efforts to extend the life of Mohave. The District will evaluate the impact, if any, of SCE's recent decision on the District's effort to extend Mohave operations. (See Note (11), Contingencies, Black Mesa Litigation, for a discussion of other related issues.) The District has included approximately $211.3 million in its Capital Improvement

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Program to cover the costs of such equipment or alternate resources, if necessary. Although the parties have been trying to reach a settlement, it is not certain if, and when, a resolution will be reached. The District has already replaced a portion of the energy and is considering several options for replacing the balance of the capacity if Mohave is not reopened.

If the negotiations are not successful and the Mohave Participants are unable to secure reasonable terms for the supply of coal and water, the Board authorized the recovery of the balance of the District's investment in Mohave in its revenue requirements prior to the closure of the plant. Consequently, it was determined that the plant's carrying value would not be realized through future revenues and a write-down of its carrying value of $66.2 million was recorded in fiscal year 2003, and an additional $5.2 million and $6.6 million of impairment was recorded in fiscal years 2005 and 2004, respectively. In accordance with accounting standards for rate-regulated enterprises (SFAS No. 71), a regulatory asset was established for $78.0 million, based on the District's expectation that any un-recovered book value at the end of 2005 would be recovered in future rates.

Deferred Charges and Deferred Credits – Deferred charges and other assets consist primarily of the following at April 30 (in thousands):

	2006	2005
Bond defeasance regulatory asset	$ 90,818	$ 93,023
Mohave Generating Station regulatory asset	75,406	78,006
Spent nuclear fuel storage regulatory asset	21,842	22,210
Derivatives market valuation	50,323	65,915
Pension intangible asset	18,001	20,300
Other	49,931	42,819
	$ 306,321	$ 322,273

If events were to occur making full recovery of these regulatory assets no longer probable, the District would be required to write off the remaining balance of such assets as a one-time charge to net revenues.

Deferred credits and other non-current liabilities consist primarily of the following at April 30 (in thousands):

	2006	2005
Asset retirement obligation	$ 183,965	$ 198,450
Accrued postretirement benefit liability	258,065	221,100
Additional pension minimum liability	1,890	66,200
Accrued decommissioning costs	5,597	33,527
Provision for contract losses	66,339	79,619
Derivatives market valuation	38,976	82,398
Accrued spent nuclear fuel storage	24,245	24,486
Accrued environmental issues	78,511	76,959
Other	62,261	57,335
	$ 719,849	$ 840,074

(10) Commitments:

Subsidiary Guarantees – The District acts as guarantor for New West Energy's contractual obligations as necessary to satisfy performance security requirements under agreements with utility distribution companies, brokers and counterparties for financial hedge transactions and power purchasers and sellers. No payments were made under these guarantees during fiscal years 2006 and 2005. Existing guarantees were terminated May 31, 2003, and New West Energy has not entered into any agreements since then.

Improvement Program – The Improvement Program represents the District's six-year plan for major construction projects and capital expenditures for existing generation, transmission, distribution and irrigation assets. For the 2007-2012 time period, the District estimates capital expenditures of approximately $5.0 billion. Major construction projects include construction of an additional unit at Springerville Generating Station, final completion of the Santan Generating Station, a new transmission line in the Southeast Valley, and other key generation, distribution and transmission projects.

Long-Term Power Contracts – The District entered into three contracts, collectively, with the United States Bureau of Reclamation (United States), the Western Area Power Administration and the Central Arizona Water Conservation District (CAWCD) for the long-term sale, through September 2011, of power and energy associated with the United States' entitlement to NGS. The amount of energy available to the District varies annually and is expected to decline over the life of the contracts. The District pays a fixed amount under the contracts, pays the cost of NGS generation and other related costs, and supplies energy at cost to CAWCD for Central Arizona Project facilities. The fixed portion of the District's payment obligations under the three contracts totals $47.0 million annually through fiscal year 2011, and $19.6 million thereafter. Of the total obligation, $25.2 million annually through fiscal year 2011 and $10.5 million thereafter are unconditionally payable regardless of the availability of power. Payments under these contracts totaled $91.5 million and $86.3 million in fiscal years 2006 and 2005, respectively.

The District entered into two other long-term power purchase agreements to obtain a portion of its projected load requirements through 2011. Minimum payments under these contracts are $38.2 million annually through fiscal year 2011 and $1.9 million thereafter. Total payments under these two contracts, including the minimum payments, were $68.4 million and $66.4 million in fiscal years 2006 and 2005, respectively. In conjunction with the impairment analysis performed on generation-related operations, the District has recorded provisions for losses on these contracts. The provisions recorded in August 1998, of $163.7 million, are being amortized over the life of the contracts, commencing January 1, 1999. Amortization of $13.3 million has been reflected as a reduction in purchased power expense in fiscal years 2006 and 2005. The remaining liability at April 30, 2006 of $66.3 million is included in deferred credits and other non-current liabilities in the Combined Balance Sheets.

In addition, beginning in the summer of 2006, the District will have 100 MW of capacity from Springerville Generating Station Unit 3, being developed by Tri-State Generation and Transmission Association, pursuant to a 30-year power purchase agreement.

Fuel Supply – At April 30, 2006, minimum payments under long-term coal supply contract commitments are estimated to be $173.2 million in fiscal year 2007, $161.3 million in fiscal year 2008, $161.3 million in fiscal year 2009, $161.3 million in fiscal year 2010, $162.3 million in fiscal year 2011 and $539.1 million thereafter.

Springerville Generating Station – In 2001 the District entered into an agreement with UniSource Energy Development Company (UniSource) for the joint development of two additional coal-fired generating units (Units 3 and 4), approximately 400 MW each in size, to be located at the existing Springerville (Arizona) Generating Station. Under an amendment to the agreement, dated October 20, 2003, the District entered into a 30-year power purchase agreement (the PPA) to purchase 100 MW of capacity from Unit 3, which is being developed by Tri-State Generation and Transmission Association, Inc. Unit 3 is anticipated to be placed in service in July 2006. In addition, the District received the right to construct the fourth unit (Unit 4) at any time during the term of the PPA. The District holds such rights in its wholly-owned subsidiary, Springerville Four. The District has determined to build Unit 4 and expects it to be in service by the end of calendar year 2009. Construction plans and financing have not been finalized yet. UniSource's affiliate, Tucson Electric Power Company, will operate both units.

(11) Contingencies:

Nuclear Insurance – Under existing law, public liability claims arising from a single nuclear incident are limited to $10.8 billion. PVNGS Participants insure for this potential liability through commercial insurance carriers to the maximum amount available ($300.0 million) with the balance covered by an industry-wide retrospective assessment program as required by the Price-Anderson Act. If losses at any nuclear power plant exceed available commercial insurance, the District could be assessed retrospective premium adjustments. The maximum assessment per reactor per nuclear incident under the retrospective program is $100.6 million including a 5% surcharge, applicable in certain circumstances, but not more than $15.0 million per reactor may be charged in any one year for each incident.

Based on the District's ownership share of PVNGS, the maximum potential assessment would be $52.8 million, including the 5% surcharge, but would be limited to $7.9 million per incident in any one year.

Spent Nuclear Fuel – Under the Nuclear Waste Policy Act of 1982, the District pays $0.001 per kWh on its share of net energy generation at PVNGS to the U. S. Department of Energy (DOE). The DOE was responsible for the selection and development of repositories for permanent storage and disposal of spent nuclear fuel not later than December 31, 1998. Because of the significant delays in the DOE's schedule, it cannot be determined when the DOE will accept waste from PVNGS or from the other owners of spent nuclear fuel. It is unlikely, due to PVNGS' position in DOE's queue for receiving spent fuel, that Arizona Public Service Company (APS), the operating agent of PVNGS, will be able to initiate shipments to DOE during the licensed life of PVNGS. Accordingly, APS has constructed an on-site dry cask storage facility to receive and store PVNGS spent fuel. The facility stored its first cask in March 2003. Forty-one casks are now stored on site.

The District's share of on-site interim storage at PVNGS is estimated to be $33.1 million for costs to store spent nuclear fuel from inception of the plant through fiscal year-end 2006, and $2.8 million per year going forward. These costs have been included in the District's regulated operations price plans for transmission and distribution.

Black Mesa Litigation – Navajo Nation v. Peabody (US Dist. Court, D.C. District) – In June 1999, the Navajo Nation filed a lawsuit in the United States District Court in Washington D.C. (the "U.S. District Court"), alleging that Peabody, Southern California Edison Company (operating agent for Mohave), the District (operating agent for NGS) and certain individual defendants, induced the United States to breach its fiduciary duty to the Navajo Nation, and violated federal racketeering statutes. The lawsuit arises out of negotiations culminating in 1987 with amendments to the coal leases and related agreements. The suit alleges $600.0 million in damages. The plaintiffs also seek treble damages against the defendants, measured by any amounts awarded under the racketeering statutes. In addition, the plaintiffs claim punitive damages of not less than $1.0 billion. In March 2001, the Hopi Tribe intervened in the suit. The claims of both the Navajo Nation and the Hopi Tribe were dismissed in their entirety with respect to the District, but the dismissal is appealable.

On February 9, 2005, the U.S. District Court granted a motion to stay the litigation until further order of the court. The parties are in mediation with respect to this litigation and related business issues.

Navajo Nation v. United States (Court of Federal Claims) – Previously, the Navajo Nation had filed a suit against the United States Government based on similar allegations. The lawsuit was dismissed, but on appeal, it was reinstated and the Court of Appeals, in August 2001, held that the United States had breached its fiduciary duty under certain specific statutes to the Navajo Nation, and that a claim for damages was within the jurisdiction of the Court of Federal Claims. In March 2003, the United States Supreme Court, reversed the decision of the Court of Appeals and remanded the case for further proceedings consistent with its opinion. Instead of dismissing the case, the Court of Appeals remanded the case to the Court of Federal Claims and ordered that court to determine whether other statutes and regulations impose enforceable fiduciary duties upon the United States in connection with Peabody's leases and, if so, whether the United States breached such duties.

Peabody Legal Fees Cases – Peabody claims it is entitled to reimbursement under both the NGS Coal Supply Agreement and the Mohave Coal Supply Agreement for its costs associated with the defense of the challenges by the Navajo Nation and Hopi Tribe to these coal leases (see above matters). Peabody has filed two separate lawsuits against the NGS and Mohave Participants, respectively, seeking recovery of these fees. The Mohave and NGS Participants dispute Peabody's attempt to recover its legal costs under the coal leases.

As for the Mohave fees, the District has been dismissed from the litigation and awarded its attorney's fees. On appeal, however, the case was remanded to determine whether the District should remain in the lawsuit.

The Mohave Participants and Peabody executed a settlement agreement pursuant to which Peabody granted the Mohave Participants a waiver for fees incurred prior to January 2006. However, as described above, the lawsuit for fees arising after December 2005 continues.

Peabody's claims against the NGS Participants were dismissed. Peabody has appealed this ruling.

Peabody v. SRP – Peabody has also filed suit in St. Louis, Missouri against the District and the other owners of NGS asserting claims against both the Participants and the District relating to liability issues associated with the Navajo Nation Lawsuit, alleged breach of the NGS Coal Supply Agreement, breach of indemnity obligations owed to Peabody as the alleged agent of the NGS Participants, and claims of tortuous interference with contracts and tortuous interference with business expectancies against the District. The claim seeks $500 million and unspecified compensatory damages, prejudgment interest, attorneys' fees and costs.

The District is unable to predict the likely outcome of these Black Mesa litigation matters at this time but does not believe that these disputes will have material adverse effects on its operations or financial condition.

Environmental – SRP is subject to numerous legislative, administrative and regulatory requirements relative to air quality, water quality, hazardous waste disposal and other environmental matters. SRP conducts ongoing environmental reviews of its properties for compliance and to identify those properties it believes may require remediation. Such requirements have resulted, and will continue to result, in increased costs associated with the operation of existing properties.

In September 2003, the District received notice from the U.S. Environmental Protection Agency (EPA) that it is potentially liable under the Comprehensive Environmental Response, Compensation and Liability Act as an owner and operator of a facility (the 16th St. facility) within the Motorola 52nd Street Superfund Site. The District may be liable for past costs incurred and for future work to be conducted within the Superfund Site. Investigation and evaluation of this potential liability are in the preliminary stages, but initial soil vapor investigations indicate some contamination on site. Further soil and groundwater investigations will take place during 2006. The District is unable at this time to predict the outcome, but believes that it has adequate reserves for this potential liability.

The EPA is continuing its national enforcement initiative under the New Source Review (NSR) provisions of the Clean Air Act (CAA). This initiative is focused on determining whether companies had failed to disclose major repairs or alterations to facilities that would have required the installation of new pollution control equipment. As part of this initiative, the District received four (4) letters from Region IX of the EPA, under the authority of Section 114 of the CAA, requesting information on Coronado Generating Station (CGS) (the Section 114 Letters). In March 2004, the District entered into negotiations with the EPA regarding possible additional control technology to reduce emission levels from District generating units. To date, EPA Region IX has taken no enforcement action against the District for alleged violations of NSR regulations at CGS. The District is unable to predict the outcome of the Section 114 Letters or negotiations with EPA Region IX with respect to potential impacts on District generating units, but is optimistic that it will reach a mutually satisfactory agreement with the EPA regarding control technology and emission limits at District facilities.

Several species listed under the Endangered Species Act (ESA) have been discovered in and around Roosevelt and Horseshoe Dams. To obtain an Incidental Take Permit (ITP) under the ESA, the District entered into formal consultation with the United States Fish and Wildlife Service (USFWS), and developed a Habitat Conservation Plan (Plan), which allows full operation of Roosevelt Dam and Reservoir, provided the District mitigates for the "taking" of species by the establishment of habitat for the species in other areas or through other measures. The USFWS issued the District an ITP for operation of Roosevelt Dam in 2003. The District has reserved funds, that it believes will be sufficient to implement the Plan.

The District engaged in similar consultations with the USFWS to obtain an ITP for operation of Horseshoe and Bartlett Dams on the Verde River by December 2007.

The USFWS designated "critical habitat" for one of the species affected by SRP reservoir operations, the Southwestern Willow Flycatcher. The final designation does not encompass lands in or near the SRP reservoirs.

NOTES TO COMBINED FINANCIAL STATEMENTS

April 30, 2006 and 2005

Air Quality – In December 1999, the participants in Mohave Generating Station settled a lawsuit alleging numerous and continuing violations of opacity and sulfur dioxide standards. Under the terms of the settlement, the participants were required to install by January 1, 2006, a sulfur dioxide scrubber and other pollution control equipment. Major plant modifications, including emissions controls, are required for continued operation as a coal-fired plant. Capital costs are estimated at $1 billion, of which the District's share would be $211.3 million. These costs are included in capital contingencies portion of the 2007-2012 Improvement Program. However, as discussed in Note (10) Regulatory Issues, Mohave Generating Station, the uncertainty in post-2005 coal and water supply have caused the Mohave Participants to be unwilling to make the necessary investments at this time.

Electric utilities are subject to continuing environmental regulation. Federal, state and local standards and procedures that regulate the environmental impact of electric utilities are subject to change. These changes may arise from continuing legislative, regulatory and judicial action regarding such standards and procedures. Consequently, there is no assurance that facilities owned by the District will remain subject to the regulations currently in effect, will always be in compliance with future regulations, or will always be able to obtain all required operating permits. An inability to comply with environmental standards could result in additional capital expenditures to comply, reduced operating levels, or the complete shutdown of individual electric generating units not in compliance. Although the prospect for new Clean Air Act legislation in 2006 is low, as a result of the legislative and regulatory initiatives, the District is planning emission reductions at its coal-fired power plants.

The EPA issued final regulations for the control of mercury emissions from coal-fired utility boilers in May 2005. The District is evaluating the impact of the final regulations, which could require the installation of new emission controls at some of its coal-fired power plants. Eleven states have filed a lawsuit challenging the EPA mercury rule claiming it is not protective enough of public health and contrary to the CAA. The District is monitoring developments associated with the lawsuit and its implications on the control requirements. The regulations give states until November 2006 to either adopt the federal programs, as described in the final EPA regulations, or establish an alternative regulatory program. Arizona has not yet decided whether to opt into the federal program or establish its own program under the CAA. The specific level of reduction and compliance cost will not be known until the state finalizes its regulatory program.

On June 15, 2005, the EPA issued final amendments to its July 1999 regional haze rule. These amendments apply to the provisions of the regional haze rule that require emissions controls known as Best Available Retrofit Technology (BART) for coal-fired power plants and other industrial facilities that emit air pollutants that reduce visibility. The amendments include final guidelines for states to use in determining which facilities must install controls and the types of controls that facilities must use. States must complete the BART determinations for eligible facilities by 2007. BART controls must be installed five years after the EPA approves a state's BART determination. The District has financial interests in several coal-fired power plants that may be subject to the new BART requirements.

The District is also closely monitoring global warming policy developments at both a federal and regional level. Federal legislation has been proposed which would cap emissions of carbon dioxide from fossil fuel power plants. There have also been several regional initiatives aimed at curbing utility carbon dioxide emission levels. The District is assessing the risk of these policy initiatives on its generation assets and is developing contingency plans to comply with any future laws and regulations restricting carbon dioxide emissions.

Coal Mine Reclamation – In management's opinion, there are sufficient accruals in the accompanying combined financial statements for the District's obligation to reimburse certain coal providers for amounts due for certain coal reclamation costs. However, the District is contesting certain other coal mine reclamation costs. Neither the District's responsibility nor the ultimate amount of liability, if any, can be determined at this time. Management does not believe that the outcome of these matters will have a material adverse effect on the District's financial position or results of operations.

Natural Gas Supply – The District had a contract with El Paso Natural Gas Company for the transportation of natural gas on a full-requirements basis. FERC converted the full requirements contract to a contract with monthly limits. A Phoenix area shipper, whose full-requirements contract was also converted, asked FERC to reallocate transportation costs among all of the Phoenix area shippers. FERC has denied this request. The shipper may appeal the decision and if successful, the approximate impact to the District could be as much as $20 million.

Proposition 200 – In November 2004, Arizona voters approved Proposition 200, Arizona Taxpayer and Citizen Protection Act (Prop. 200), which, among other things, requires state and local government employees to verify the immigration status of people applying for certain "public benefits" and to report violators to immigration authorities. The Arizona Attorney General issued an opinion in 2004 supporting a narrow interpretation of the public benefits subject to this requirement. In November 2004, a group called "Yes on Proposition 200" filed suit against the State of Arizona (the State) in the Maricopa County Superior Court arguing that the covered benefits were much broader. The court ruled in favor of the State and the matter was appealed to the Arizona Court of Appeals where it has been under advisement since January 2006. As a non-tax supported agricultural improvement district, the District does not believe that it is subject to this aspect of Prop. 200. However, if it were found to apply to the District and if "Yes on Proposition 200" is successful in its appeal, the District employees could have to verify immigration status of electric customers prior to providing service.

Prop. 200 also required that voters provide identification at the polls. The District implemented this requirement effective with its April 2006 elections. Recently, Hispanic organizations filed a lawsuit seeking injunctions against implementation of voter identification requirements enacted pursuant to Prop. 200. The District has received the approval of the U.S. Department of Justice of its voter identification requirements as has the State. The District is not a party to the recent lawsuit and no one is seeking to enjoin application of the voter identification requirements in District elections.

Voluntary Contributions in Lieu of Taxes – The Arizona Department of Revenue (ADOR) challenged the District's exclusion of contributions in aid of construction (CIAC) in calculating the total value of District property for purposes of computing voluntary contributions in lieu of taxes (in lieu contributions) paid by the District. While the District obtained a favorable ruling from the Arizona State Board of Equalization, the Arizona Tax Court subsequently rendered a favorable decision to the ADOR on appeal. The District appealed the decision of the Arizona Tax Court to the Arizona Court of Appeals. The Court of Appeals ruled in the District's favor on January 19, 2006. The ADOR filed a petition for review of this decision with the Arizona Supreme Court. If the Arizona Supreme Court accepts the petition and overturns the Court of Appeals decision, the District would be liable for approximately $13.8 million plus interest for fiscal years 2003 (four months), 2004, and 2005 (eight months). The District believes it has adequate reserves for this potential liability. For calendar years 2005 and forward, legislation has been passed that removes the value of CIAC from the in lieu contribution formula. The legislation codifies the exclusion of CIAC from computing in lieu contributions that could have had approximately $7.3 million per year effect for the District.

The Arizona Legislature also passed legislation that reduces the assessment ratio for calculation of in lieu contributions in Arizona beginning in calendar year 2006. The rate of 25% that was in effect prior to calendar year 2006 will be reduced to 20% over a 10-year period. Because the tax year is based on a calendar year, the first reduction for in lieu contributions will affect only four months of the District's fiscal year 2006. Fiscal year 2007 will be the first full fiscal year for the District, with a continual reduction through fiscal year 2016, when the assessment ratio reaches 20%. The legislation reducing the assessment ratio to 20% is expected to produce a cumulative savings of approximately $1.5 million per year.

California Energy Market Issues – Numerous FERC proceedings are addressing various aspects of the California energy market "crisis" of 2000 through 2001. Several of these proceedings involve potential refunds. Because the District bought from and sold power to the California energy market, the District has been drawn into many of the proceedings. However, the District was a net buyer in the California market during the time periods being scrutinized, and believes it is entitled to refunds if any are ordered and, in fact, has received approximately $18.8 million in refunds to date.

On March 17, 2006, the three California public utilities and the California Energy Oversight Board (CA Parties) filed lawsuits in California federal court against numerous public power utilities, including the District, that made energy sales into the California market in 2000 and 2001. The CA Parties' Notice of Claim preceding this lawsuit alleged estimated damages of $62.3 million without consideration of offsets due to the District. Additionally, on December 30, 2005, the Project received a Notice of Claim from the California Attorney General and the California Department of Water Resources with similar allegations and alleged damages of $8.5 million without consideration of offsets due to the District. No lawsuit on this Notice was filed. The District believes it has offsets as a net buyer in the California Power Market which exceed the amount of the claims asserted against it. The CA Parties, as well as the California Attorney General and the California Department of Water Resources, have executed a stand-still agreement with the District that resulted in a dismissal of the claims against the District, without prejudice, and precludes filing of litigation by the California Attorney General and the California Department of Water Resources.

Indian Matters – From time to time, SRP is involved in litigation and disputes with various Indian tribes on issues concerning regulatory jurisdiction, royalty payments, taxes and water rights, among others (see Navajo Nation Lawsuit and Air Quality above). Resolution of these matters may result in increased operating expenses.

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

The United States, on behalf of the Gila River Indian Community (GRI Community), filed a lawsuit in 1982 in the Federal District Court, District of Arizona, to protect the water right claims of the GRI Community. The Association is among the many defendants named in this lawsuit. The lawsuit claims that the defendants' use of surface water and groundwater violates the GRI Community's rights to water in certain specified areas, and requests a decree specifying the GRI Community's rights, injunctive relief to stop the alleged illegal use of water by the defendants, and damages for increased costs to the GRI Community from, among other things, having to deepen its wells. This lawsuit has been stayed pending the outcome of the Gila River Adjudication.

In 2004, the U.S. Congress enacted the Arizona Water Rights Settlement Act of 2004, which, when fully implemented, will resolve the claims of the GRI Community listed above as well as many of the claims in the Gila River Adjudication. However, there are many conditions precedent to the full effectiveness and enforceability of the act and its associated agreements.

In 1978, a water rights adjudication was initiated in the Apache County Superior Court with regard to the Little Colorado River System. The District has filed its claim to water rights in this proceeding, which includes a claim for groundwater being used in the operation of CGS. The District is unable to predict the ultimate outcome of this proceeding, but believes an adequate water supply for CGS will remain available.

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

Self-Insurance – The District maintains various self-insurance retentions for certain casualty and property exposures. In addition, the District has insurance coverage for amounts in excess of its self-insurance retention levels. The District provides reserves based on management's best estimate of claims, including incurred but not reported claims. In management's opinion, the reserves established for these claims are adequate and any changes will not have a material adverse effect on the District's financial position or results of operations.

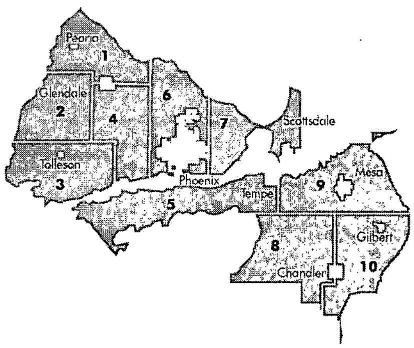
REPORT OF INDEPENDENT AUDITORS

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

In our opinion, the accompanying combined balance sheets and the related combined statements of net revenues and comprehensive income (loss), and cash flows present fairly, in all material respects, the financial position of Salt River Project Agricultural Improvement and Power District and its subsidiaries and the Salt River Valley Water Users' Association (collectively, "SRP") at April 30, 2006 and 2005, and the results of their operations and their cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of SRP's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

PricewaterhouseCoopers, LLP
Los Angeles, California
June 15, 2006

SRP Voting Areas



The 10 SRP voting areas for SRP Boards and Councils are indicated in color; total area equals 375 square miles.

SRP Boards

The two Boards of Salt River Project work with management to establish policies to further the business affairs of SRP.

The Salt River Valley Water Users' Association (the "Association") is SRP's private water corporation, which administers the water rights of SRP's 375-square-mile water service area, and operates and maintains the irrigation and drainage system. The 10 members of the Association Board of Governors serve staggered four-year terms and are elected from voting districts by the landowners within the water service territory.

The Salt River Project Agricultural Improvement and Power District (the "District") is SRP's public power utility and a political subdivision of Arizona. The 14 members of the District Board of Directors serve staggered four-year terms. Ten District Board members are elected from voting divisions and four are elected at-large by landowners within the District's boundaries. Most often, candidates seek election to both Boards.

SRP Councils

The two Councils of Salt River Project enact and amend bylaws relating to business affairs of SRP and also serve as liaisons to District electors and Association shareholders.

As with the SRP Boards, there is one Council for the Association and one for the District. The 30 Association Council members are elected to staggered four-year terms from 10 districts. The 30 District Council members are elected to staggered four-year terms from 10 divisions. Most often, candidates seek election to both Councils.

Boards Association & District

Larry D. Rovey District/Division 1
Shirley Long District/Division 2
Elvin E. Fleming District/Division 3
Gilbert R. Rogers District/Division 4
Carl E. Weiler District/Division 5
Jack M. White Jr. District/Division 6
Keith B. Woods District/Division 7

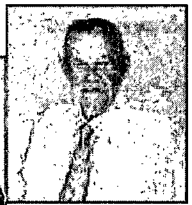
Robert G. Kempton District/Division 8
Dale C. Riggins Jr. District/Division 9
Dwayne E. Dobson District/Division 10
Carolyn Pendergast Director-at-large, seat 11
William W. Arnett Director-at-large, seat 12
Fred J. Ash Director-at-large, seat 13
Wendy Marshall Hancock Director-at-large, seat 14

Councils Association & District

District/Division 1


John R. Starr


Kevin J. Johnson


Robert L. Cook

District/Division 2


John A. Vanderwey


Paul E. Rovey


Richard A. Boulais

District/Division 3


Robert T. Van Hofwegen


Mario J. Herrera


John E. Anderson

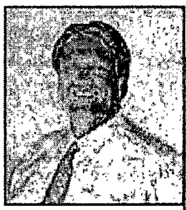
District/Division 4


Lloyd E. Banning
Chairman


Charles D. Coppinger


Leslie C. Williams

District/Division 5


John R. Shelton


Stephen H. Williams


Ramon P. Trujillo

District/Division 6


Robert W. Warren


Ben A. Butler


Jacqueline L. Diller Miller

District/Division 7


Ann M. Burton


Mark A. Lewis


Harmen Tjaarda Jr.

District/Division 8


Deborah S. Hendrickson


Christopher J. Dobson


Mark L. Farmer

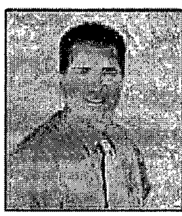
District/Division 9


W. Curtis Dana


Arthur L. Freeman


Edward E. Johnson

District/Division 10


William P. Schrader Jr.


Mark V. Pace
Vice Chairman


Orland R. Hatch

D. Michael Rappoport David G. Areghini Jane D. Alfano L.J. U'Ren Mark B. Bonsall Richard M. Hayslip John F. Sullivan

Corporate Officers

John M. Williams Jr.
President

David Rousseau
Vice President

Terrill A. Lonon
Secretary

Steven J. Hulet
Treasurer

Executive Management

Richard H. Silverman
General Manager

David G. Areghini
Associate General Manager
Power, Construction & Engineering Services

Mark B. Bonsall
Associate General Manager
Commercial & Customer Services

D. Michael Rappoport
Associate General Manager
Public & Communications Services

John F. Sullivan
Associate General Manager
Water Group

L.J. U'Ren
Associate General Manager
Operations, Information & Human Resources Services

Jane D. Alfano
Corporate Counsel

Richard M. Hayslip
Assistant General Manager
Environmental, Land, Risk Management & Telecom

Corporate Headquarters

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SRP
1521 N. Project Drive
Tempe, Arizona 85281-1298

Mailing address
SRP
P.O. Box 52025
Phoenix, AZ 85072-2025

Financial Inquiries

Dean Yee, Manager, SRP Financial Services
(602) 236-5231

Requests for Annual Reports

For additional copies of this report, or SRP quarterly reports, call SRP at (602) 236-2598.

Changes to Mailing List

For corrections or other changes to the mailing list for this report, call SRP at (602) 236-2564.

Bondholder Information

For all bond information, call the SRP Treasury Department at (602) 236-2222.

www.srpnet.com

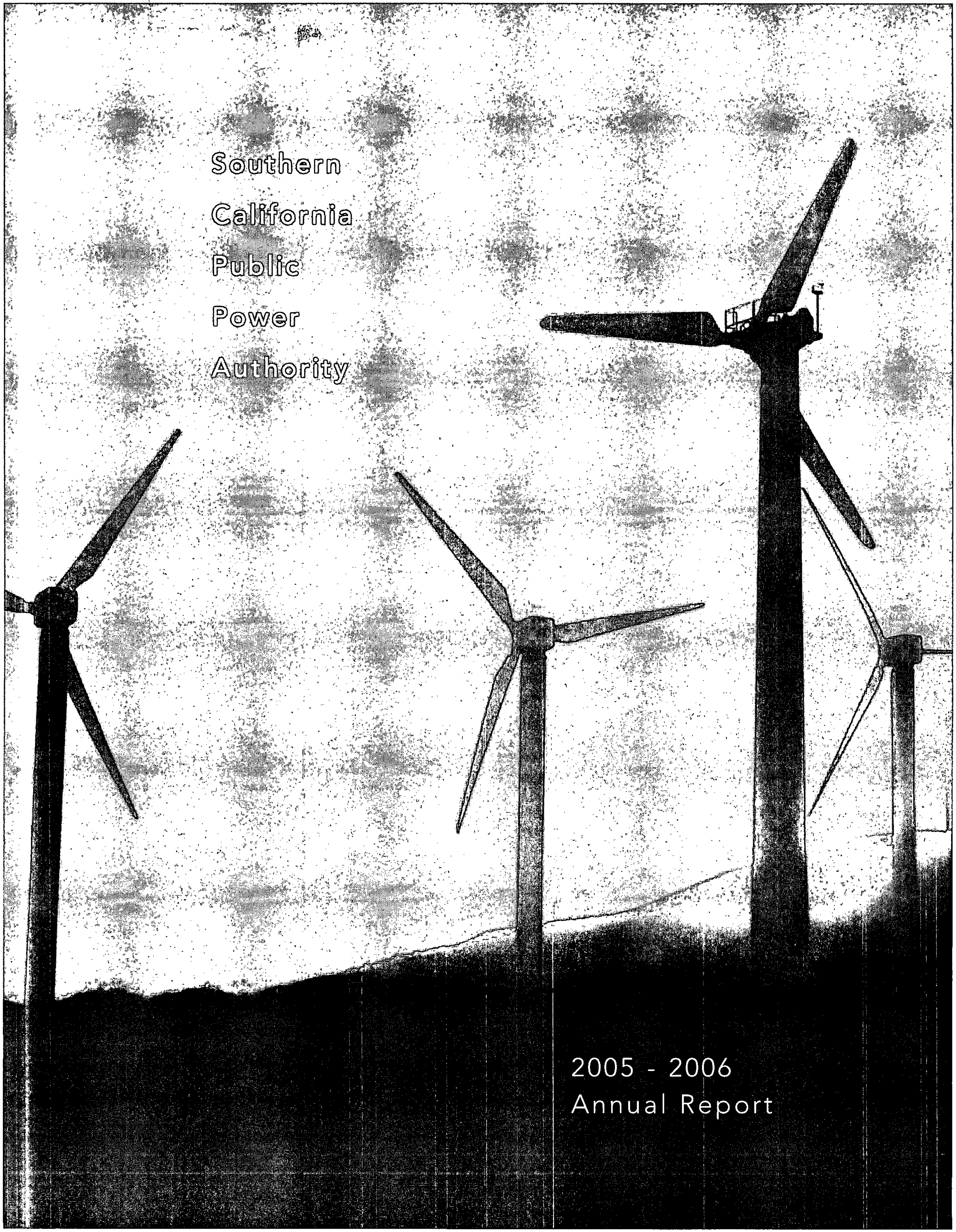
Five-year Operational and Statistical Review

Financial Data ($000)	**2006**	**2005**	**2004**	**2003**	**2002**
Total operating revenues	$2,521,970	$2,251,723	$2,077,314	$1,893,549	$2,214,378
Retail electric revenues	1,885,912	1,709,213	1,622,305	1,474,284	1,476,387
Water revenues	12,036	12,786	11,818	12,426	14,272
Other revenues	624,022	529,724	443,191	406,839	723,719
Total operating expenses	2,139,702	1,815,538	1,867,397	1,729,484	2,110,121
Total other income, net	158,966	31,902	28,615	27,467	52,304
Net financing costs	125,834	105,637	115,605	138,135	148,599
Net revenues for the year	415,400	362,450	112,220	46,669	19,796
Taxes and tax equivalents	100,953	105,475	100,693	90,388	86,255
Utility plant, gross	9,384,134	9,043,377	8,726,559	8,191,576	7,841,713
Long-term debt	2,893,017	2,727,348	2,912,849	2,809,581	3,033,931
Electric revenue contributions to support water operations	34,161	56,672	62,925	44,222	32,219

Selected Data*					
Debt service coverage ratio	2.42	2.39	2.00	2.20	2.98
Debt ratio	47.9	50.1	55.2	56.0	56.9
Total electric sales (million kWh)	36,867	35,516	33,806	35,166	36,534
Peak SRP retail customers (kW)	6,044,000	5,665,000	5,673,000	5,296,000	5,164,000
Water deliveries (acre-feet)		860,584	890,424	848,791	1,011,214
Runoff (acre-feet)		2,055,554	702,974	778,786	288,676
Employees at year-end	4,328	4,336	4,267	4,231	4,252
Customers at year-end	892,875	858,314	824,416	796,171	772,791

****Water data is by calendar year, all other data is by fiscal year ending April 30.***

SRP®



Southern California Public Power Authority

2005 - 2006
Annual Report

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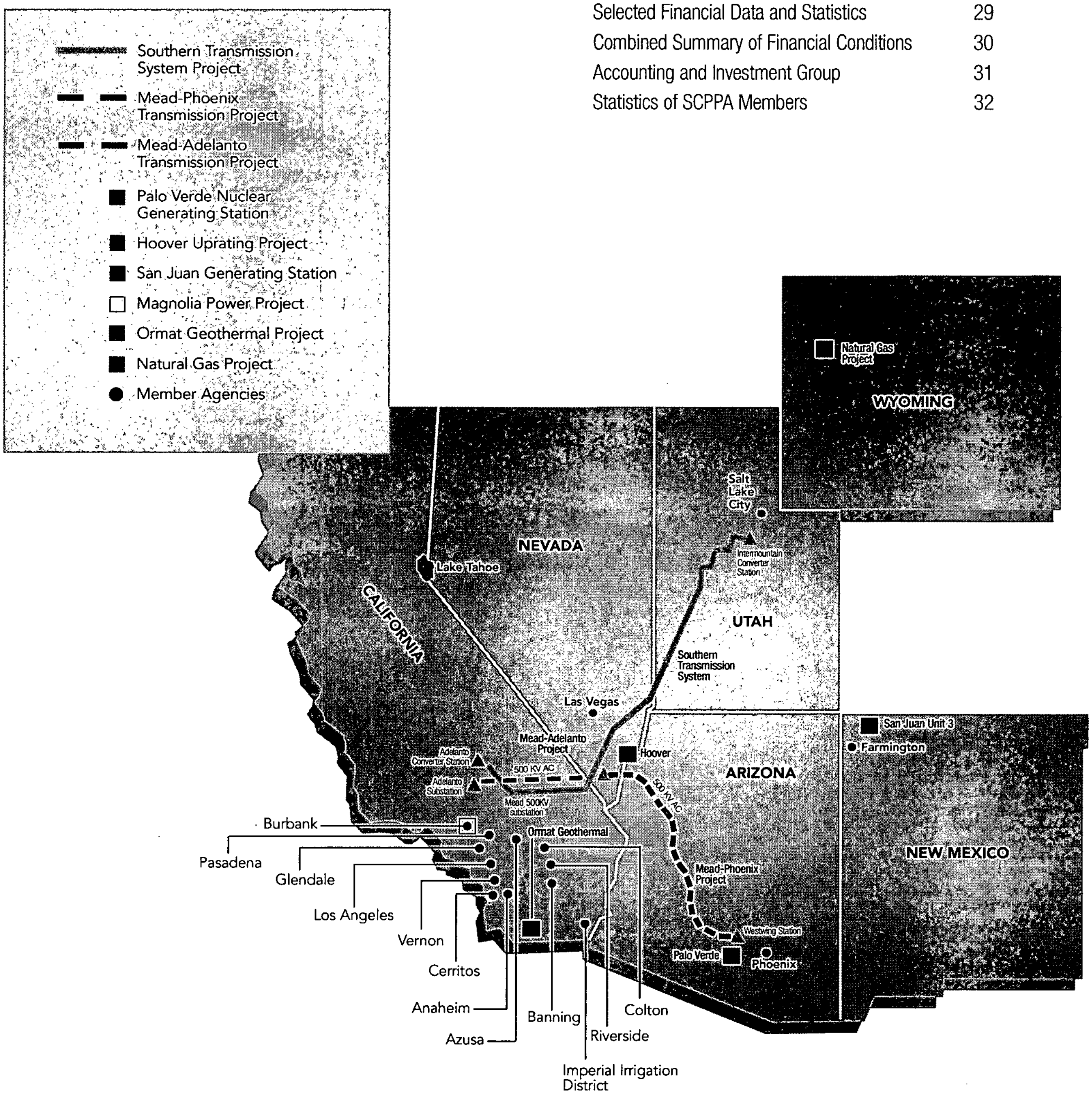
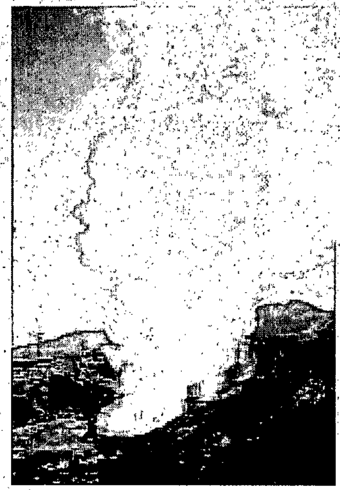


Mission

SCPPA provides financing and oversight for large joint projects in the electric utility industry and through coordinated efforts, facilitates, implements, and communicates information relative to issues and projects of mutual interest to its members as determined by the Board of Directors.



What is SCPPA?

Southern California Public Power Authority (SCPPA) is a joint powers agency consisting of non-profit, locally owned and governed public power systems comprising eleven municipal utilities and one irrigation district. Formed in 1980, SCPPA was created for the purpose of providing joint financing, construction and operation of transmission and generation projects. Today, SCPPA fulfills a wide range of services for its members by providing effective forums of collaboration though committees such as Customer Service, Finance, Public Benefits, Resource Planning, Transmission and Distribution Engineering and Operations, Natural Gas, and Renewable Energy Resources.

SCPPA is a public agency, governed locally, customer owned, vertically integrated, with an obligation to serve by planning to meet long-term needs of its customers through ownership of generation and/or transmission and long-and-short term contracts for power supplies or transmission. SCPPA has diversified its power supplies, including natural gas, renewable resources, and optimizes its energy resources with aggressive, local demand-side management programs.

SCPPA's members consist of the municipal utilities of Anaheim, Azusa, Banning, Burbank, Cerritos, Colton, Glendale, Los Angeles, Pasadena, Riverside, and Vernon, and the Imperial Irrigation District, that together deliver electricity to over 2 million customers in the southern California basin that spans an area of 7,000 square miles, and with a total population that exceeds 5 million.

The Authority currently has four generation projects, three transmission projects, and a natural gas project in operation, generating and bringing power from Arizona, New Mexico, Utah, and Nevada. Its fourth generation project, wholly owned by the Authority, is a combined cycle natural gas-fired generating plant with a nominally rated net base capacity of 242 megawatts that began commercial operation in summer 2005.

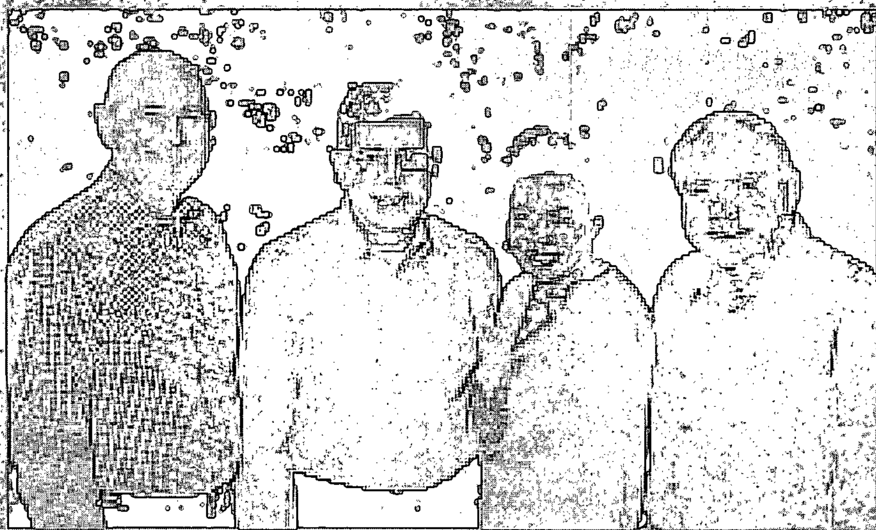
SCPPA's projects have been financed through the issuance of tax-exempt bonds, backed by the combined credit of the SCPPA members participating in each project. As of June 30, 2006, SCPPA had issued $10.1 billion in bonds, notes, and refunding bonds, of which $1.9 billion was outstanding. These bonds are backed by one of the highest credit ratings by Moody's and Standard and Poor's.

In order to support its primary purpose, SCPPA is also involved in legislative advocacy, contracting for support services, sharing of information, administrative services, analyses, training and regulatory monitoring on behalf of its members.

Vision

SCPPA will provide cost-effective joint action services that supplement member programs and activities, and that secure long-term physical supplies at predictable pricing levels for usage in power generation to assure continued member success.

SCPPA Officers & Staff



From left to right: David H. Wright, Vice President, Ronald O. Vazquez, Secretary, Phyllis E. Currie, President, Bill D. Carnahan, Executive Director

From left to right: Geri Mitchell, Office Manager, Manny Robledo, Energy Systems Manager, Phyllis Brown, Government Affairs Manager, Craig Koehler, Finance and Accounting Manager, Salpi Bouboushian, Administrative Analyst, Richard Helgeson, General Counsel, Steve Homer, Project Administrator, and Bill Carnahan, Executive Director.

President's Letter

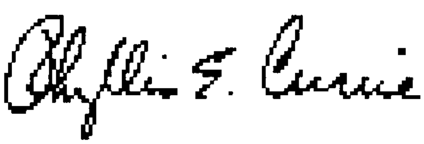
Last year marked a historic event in SCPPA's history, with the celebration of its 25th anniversary. As we look back on SCPPA's beginnings, we can clearly see that the role of SCPPA has greatly evolved. It all began a quarter of a century ago, when SCPPA invested in its first project, the Palo Verde Nuclear Generating Station. Over the years, investments in additional generating and transmission projects were added to meet the growing needs for power of our member utilities. Today, SCPPA participates in four major generation projects, a natural gas project, and has three transmission projects in operation, bringing electricity to Southern California from Arizona, Nevada, New Mexico, and Utah. On a combined basis, SCPPA's members currently deliver electricity and services to over 2 million customers covering an area of approximately 7,000 square miles.

SCPPA has evolved from its traditional role of providing financing for our Members' generation and transmission projects. SCPPA serves the Members in many other ways by providing effective forums of collaboration though committees such as Customer Service, Finance, Public Benefits, Resource Planning, Transmission Distribution Engineering and Operations, Natural Gas, and Renewable Energy. In addition to assisting the members with best practices, it also serves as a conduit for joint contracting for services, fuel acquisition for power generation, as well as, acquisition of renewable supplies such as wind and geothermal.

Through its strategic planning process, SCPPA develops a common vision for its members and a basis for joint action. Over the years, SCPPA's success has been attributable to the members' effective use of joint action. This was never more apparent than with last year's addition of SCPPA's Magnolia Power Project (MPP), its first wholly-owned and operated power plant which began operation in September, 2005. The MPP operates under the most stringent environmental standards in the nation, consisting of natural gas-fired combined cycle generation that serves the communities of Anaheim, Burbank, Cerritos, Colton, Glendale, and Pasadena. In its visionary planning, SCPPA's members also realized a need to hedge the volatile natural gas prices and invested in natural gas reserves. SCPPA also continues its commitment in renewable energy with its latest request for proposals and consideration for additional renewable resource supplies, such as solar, wind, and geothermal.

On the regulatory fronts, SCPPA remains a strong advocate and continues its involvement at both state and federal levels to protect represented customers by assuring adequate resources, reliability, and responsibility to the communities we serve. In July, I provided testimony at a hearing at the House Government Reform, Energy and Resources Subcommittee on a recently-released report by the Federal Energy Regulatory Commission (FERC) on the Summer 2006 Energy Assessment, which examined resource adequacy in all regions of the country. I raised concerns about the effect the California Independent System Operator's (CAISO's) Market Redesign and Technology Upgrade (MRTU) proposal that had been filed at FERC, would have on the long-term investment by the utilities and system reliability. Rules that investors understand and that reduce their risks are key to attracting capital investment in generation and transmission facilities. SCPPA members continue to be concerned that the complex market design rules contained in the MRTU will discourage development of needed generation and transmission facilities and inhibit efficient use of available resources on a regional basis. Of specific concern, is the failure of the MRTU proposal to ensure that load-serving entities in California are able to obtain long-term transmission rights, as directed by Congress in EPAct 2005. The long-term transmission rights provision was a key battle during debate on the electricity title of the bill, and one that SCPPA and other public power associations fought hard to secure, in order to have reasonable certainty about the delivered cost of power to consumers. Even though the FERC conditionally approved the CAISO's MRTU proposal in September 2006, SCPPA's and the other public power association's efforts in addition to numerous letters received from House and Senate members from other states in the Western Interconnection were instrumental in influencing FERC to inform CAISO that they must also comply with its rule on Long-Term Transmission Rights (LTTRs). SCPPA is currently working with the California Municipal Utility Association (CMUA) and others, to highlight and propose solutions to key issues in the MRTU plan, identify resource adequacy requirements, in addition to providing assistance with the implementation of LTTR for load-serving entities.

SCPPA's history and continued success throughout the year, has defined its evolving role. By working together, SCPPA members are providing and delivering reliable service at competitive and stable rates. Whether through proactive advocacy impacting energy legislation and regulation in California or at the Federal level, or collectively meeting our commitments for conservation and renewable energy resources, SCPPA members have worked together to successfully meet the challenges in California's electric energy industry. SCPPA and its Members are committed to work together though a proven system of joint action. Southern California Public Power Authority proudly serves its Members and will continue to find ways to contribute value in the years to come.



Phyllis E. Currie, President

Executive Director's Letter

Following the celebration of SCPPA's 25th Anniversary, it is important to reflect on how the Authority has evolved. SCPPA originally came into existence to aid the public power systems in Southern California, and to provide financing for their participation in electric generating facilities and high voltage transmission lines. SCPPA marked its beginning with investment in its first project some 25 years ago by issuing revenue bonds and obtaining an undivided ownership interest in the Palo Verde Nuclear Generating Station Units 1, 2, and 3. Shortly thereafter, SCPPA added a second project, known as the Southern Transmission System and in 1984 obtained financing that was used for payments-in-aid of construction made to the Intermountain Power Agency (IPA) for costs of acquisition and construction of a 500-kV DC bi-pole transmission line from a coal-fired steam-electric generating plant and switchyard in Millard County, Utah to Adelanto, California. The transmission line spans a distance of approximately 490 miles in length, connecting two AC/DC converter stations at either end and several microwave communication facilities.

In 1986, the Authority added its third project by investing in the uprating of Hoover Power Plant's generating units. In 1992, the Authority continued to grow by entering into an agreement to acquire an interest in the Mead-Phoenix Project ("Mead-Phoenix"), a transmission line extending between the Westwing substation in Arizona and the Marketplace substation in Nevada. The agreement provides the Authority with an 18.31% interest in the Westwing-Mead project component, a 17.76% interest in the Mead Substation project component and a 22.41% interest in the Mead-Marketplace project component. The Authority also entered into an agreement to acquire a 67.92% interest in the Mead-Adelanto Project ("Mead-Adelanto"), a transmission line extending between the Adelanto substation in Southern California and the Marketplace substation in Nevada. Funding for these projects was provided by a transfer of funds from the Multiple Project Fund. Commercial operations commenced in April 1996.

Today, SCPPA consists of its original eleven members: Anaheim, Azusa, Banning, Burbank, Colton, Glendale, Los Angeles, Pasadena, Riverside, Vernon, and the Imperial Irrigation District; and its newest member Cerritos, who joined SCPPA in 2003. Together they deliver electricity and provide services to over 2 million customers covering an area of approximately 7,000 square miles. SCPPA's investments have traditionally been in the areas of coal, hydroelectric, natural gas-fired generation, and nuclear, as well as high voltage transmission that delivers electric energy to California. With the addition of the Magnolia Power Project, Natural Gas Project, and Ormat Geothermal Project, SCPPA has experienced over a 50% growth rate. I am honored to have been associated with SCPPA for most of its existence, and proudly serve as its Executive Director now in my 7th year.

One of the most important project additions is the Magnolia Power Project (MPP), SCPPA's first wholly-owned and operated project, that began commercial operation in September 2005. MPP is a combined cycle natural gas-fired plant, located in Burbank, California, with Burbank Water and Power acting as the Project manager and operator for SCPPA, The plant generates 242 megawatts to meet base-load capacity and has a peaking capacity in excess of 300 megawatts. While meeting the strictest environmental standards and regulations in the nation, MPP utilizes the latest technology requiring less fuel, and is more efficient than older power plants it replaced.

On July 1, 2005, the Authority, together with the Los Angeles Department of Water and Power and the Turlock Irrigation District, acquired 42.5% of an undivided working interest in three natural gas leases located in the Pinedale Anticline region of the State of Wyoming. The purchase included 38 operating oil and gas wells and associated lateral pipelines, equipment, permits, rights of way, and easements used in production. The natural gas field production is expected to increase for several more years as additional capital is invested on drilling new wells. This purchase, along with similar future purchases, will provide a secure source of gas for the participants, and hedge against volatile prices in the market.

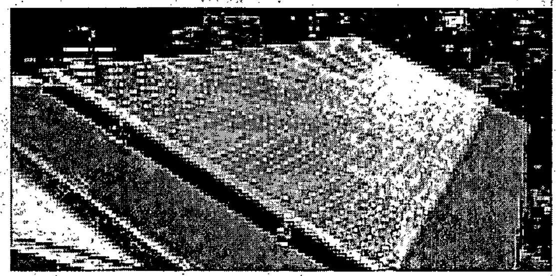
SCPPA continues in its expanding role to meet the challenges facing the electric industry. In order to meet the renewable power mandate, geothermal energy power was added to its portfolio with the Ormat Geothermal Project. The Authority entered into long-term Power Purchase Agreements in December 2005 with divisions of Ormat Technologies, Inc. for 20 megawatts ("MW") of electric generation from geothermal energy facilities. In addition, other renewable projects were also under consideration at year-end, including wind, solar, and geothermal.

The continued success and growth of SCPPA has augmented the Member's ability to keep pace with the local demand for energy. SCPPA's success has been attributable to the collective and visionary leadership of its members, and working together we know that we will be ready for whatever challenges we encounter. With the uncertainty in California's electricity industry, one thing can be counted on – that the role of SCPPA will continue to evolve as its Members characterize and chart its future to meet the new challenges head-on.

Bill D. Carnahan, Executive Director

SCPPA's Evolving Role

The role of Southern California Public Power Authority, also known as SCPPA, continues to evolve as we find new ways, as a Joint Action Agency, to bring value to our Members so they remain positioned to meet the challenges within our industry. The Members of SCPPA are each independent and locally owned and highly successful utilities. They provide reliable energy at competitive and stable rates with responsibility and sensitivity to the communities and the environment in which they serve. Working together through SCPPA, these agencies have leveraged their talents, resources, and financial strength to collectively bring more value to their communities. Created in 1980, SCPPA continues in its traditional roles of providing financing for our Members' generation, transmission, and natural gas projects; managing various projects; and finding ways to reduce capital costs through debt refinancing. Over the last few years, SCPPA has been expanding its role in order to meet the challenges facing our industry.

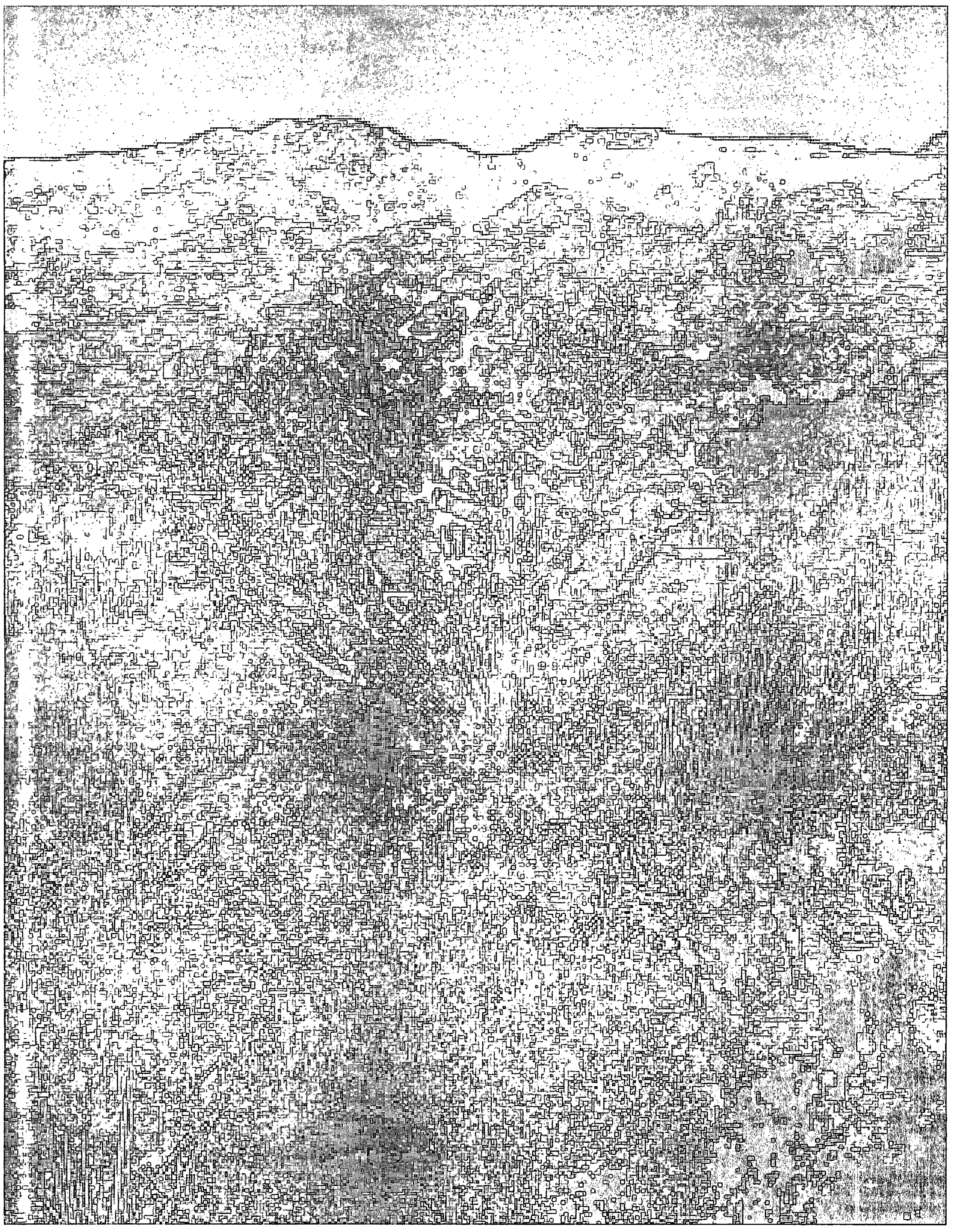


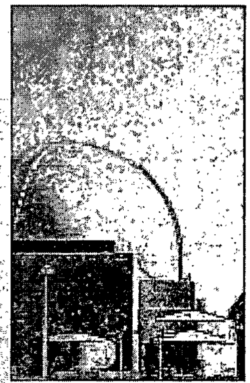
After celebrating its success throughout its first twenty-five years as a Joint Action Agency, SCPPA now directs its attention to the future. But in order to understand SCPPA's next roles, it is important to reflect on how the Authority has evolved to its present state today. SCPPA was formed by the public power systems, commonly known as municipal electric utilities, in Southern California to provide financing for their participation in electric generating facilities and high voltage transmission lines. SCPPA began with an investment in its first project 25 years ago by issuing revenue bonds and obtaining an undivided ownership interest in the Palo Verde Nuclear Generating Station. Slowly it added additional generating and transmission projects to support the Member's needs as the demands for power increased. SCPPA through its Members: Anaheim, Azusa, Banning, Burbank, Cerritos, Colton, Glendale, Los Angeles, Pasadena, Riverside, Vernon, and the Imperial Irrigation District, has been providing electricity and water services to most of their cities for over a century. Since 1980, SCPPA's members have worked together and, on a combined basis, presently deliver electricity and provide services to over 2 million customers covering an area of approximately 7,000 square miles. SCPPA is a participant in three major generation projects and three transmission projects in operation, generating and bringing power from Arizona, New Mexico, Utah and Nevada.

To continue to meet the Members' needs, the Authority added three additional projects and recognized significant growth over the previous year. SCPPA's fourth generation project, the Magnolia Power Project (MPP), was added and began commercial operation in September 2005. The MPP consists of natural gas-fired combined cycle generation with a nominal rating of 242 megawatts ("MW"), and serves the communities of Anaheim, Burbank, Cerritos, Colton, Glendale, and Pasadena. On July 1, 2005, SCPPA acquired an undivided working interest in three natural gas leases located in the State of Wyoming as a hedge against volatile natural gas prices in the marketplace. This purchase includes 38 operating oil and gas wells and other ancillary assets associated with production. At year-end, other acquisition properties were also under consideration. This purchase, aligned with the core initiative in SCPPA's natural gas reserve acquisition and along with other purchases, will provide a secure source of gas for the participants for years to come.

SCPPA's role has also continued to change as it serves the Members' commitment to acquire additional renewable energy sources. To further this endeavor, SCPPA acquired geothermal energy through the addition of the Ormat Geothermal Project, which began delivering power in January 2006. Through long-term Power Purchase Agreements with divisions of Ormat Technologies, Inc., SCPPA will acquire 20 MW of electric generation from geothermal energy facilities located in Heber, California. At year-end, SCPPA had issued request for proposals and was considering additional renewable energy projects.

SCPPA's role continues to evolve as it creates solutions to meet the Member's needs and the challenges that our industry faces. SCPPA has been redefined from its traditional roles to the full service Joint Action Agency that it is today. SCPPA is here today to bring value and its role to serve its Members will certainly continue to expand as new challenges come our way.

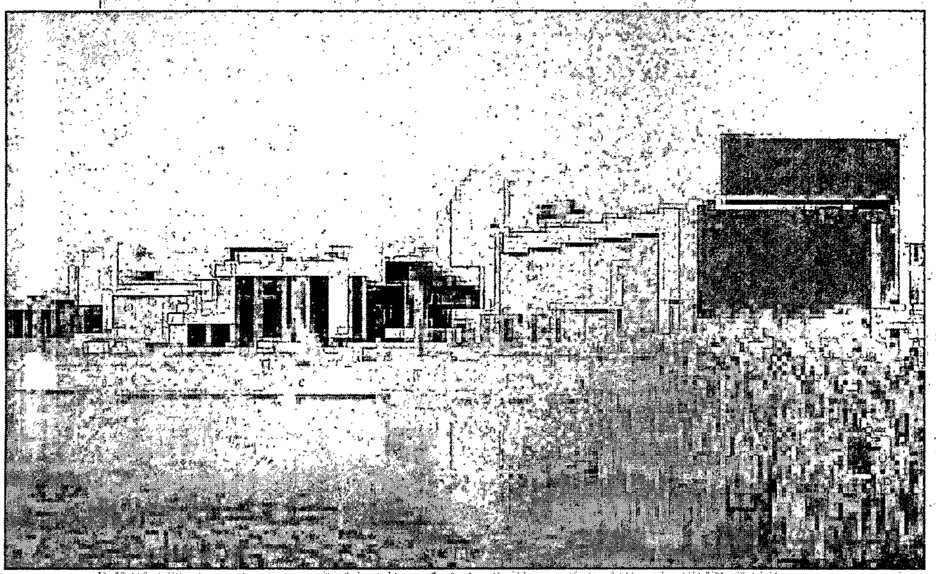




Palo Verde Operations

The steam generators in Unit 1 were successfully replaced during the fall of 2005. Unit 2's steam generators were replaced in 2003, and Unit 3's steam generators will be replaced in 2007.

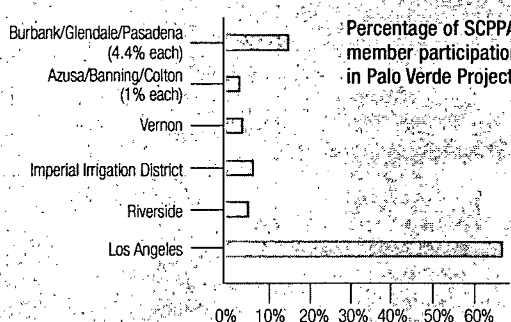
Following installation of the new steam generators and associated modifications, Unit 1's net capacity rating increased by 68 MW, but it developed a vibration problem in a cooling system pipe. After an extensive period of operation at reduced power, the vibration problem was resolved, and Unit 1 is operating at full power.



PRODUCTION COST

(Operation and Maintenance plus Nuclear Fuel)

Calendar Year	Cents per kWh
1993	2.02
1994	1.93
1995	1.61
1996	1.45
1997	1.33
1998	1.28
1999	1.25
2000	1.25
2001	1.27
2002	1.28
2003	1.32
2004	1.45
2005	1.63



Percentage of SCPPA member participation in Palo Verde Project

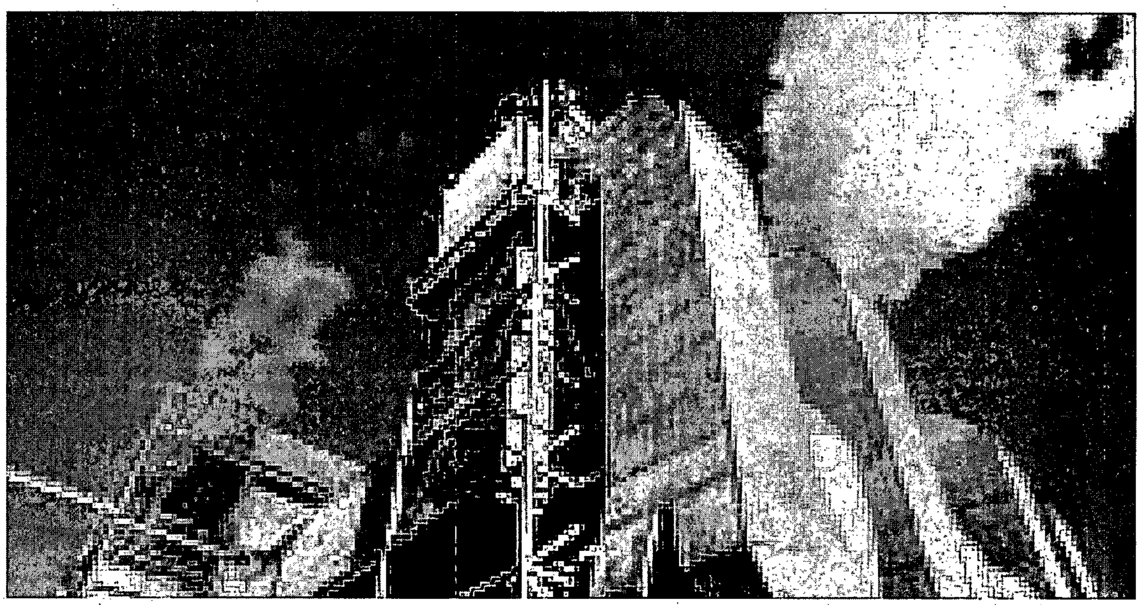
2005-2006 OPERATIONS

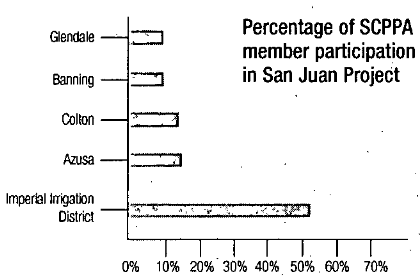
	Generation (Millions of MWHs)	Capacity Utilization (%)
Unit 1	2.8	24.9%
Unit 2	10.9	95.3%
Unit 3	8.8	80.6%
Aggregate	22.5	66.9%

San Juan Unit 3 Operations

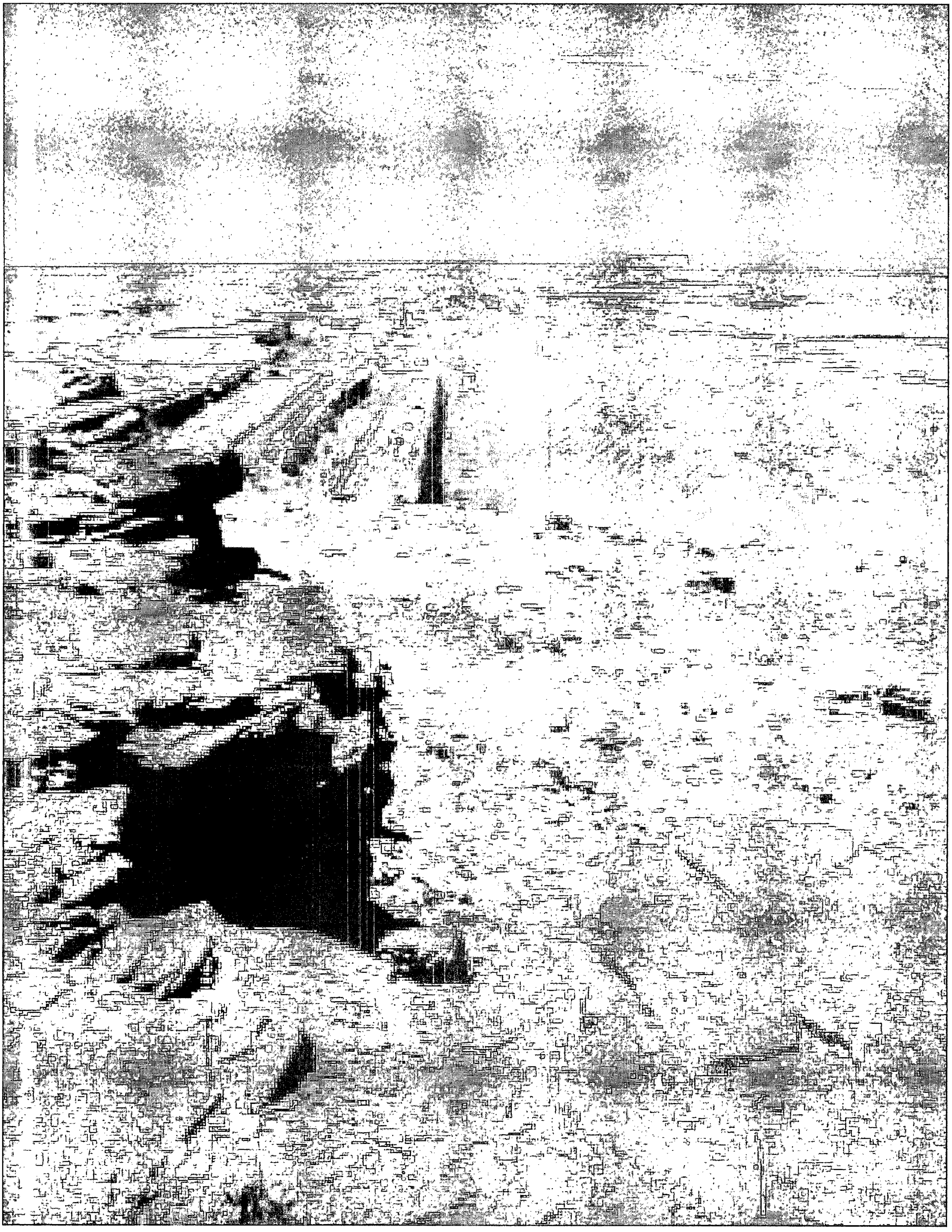
Five SCPPA participants own 41.8% of Unit 3 at the San Juan Generating Station, a coal-fired plant in New Mexico. A series of Interim "Invoicing" Agreements for fuel has led to high capacity factors and lower per unit fuel costs.

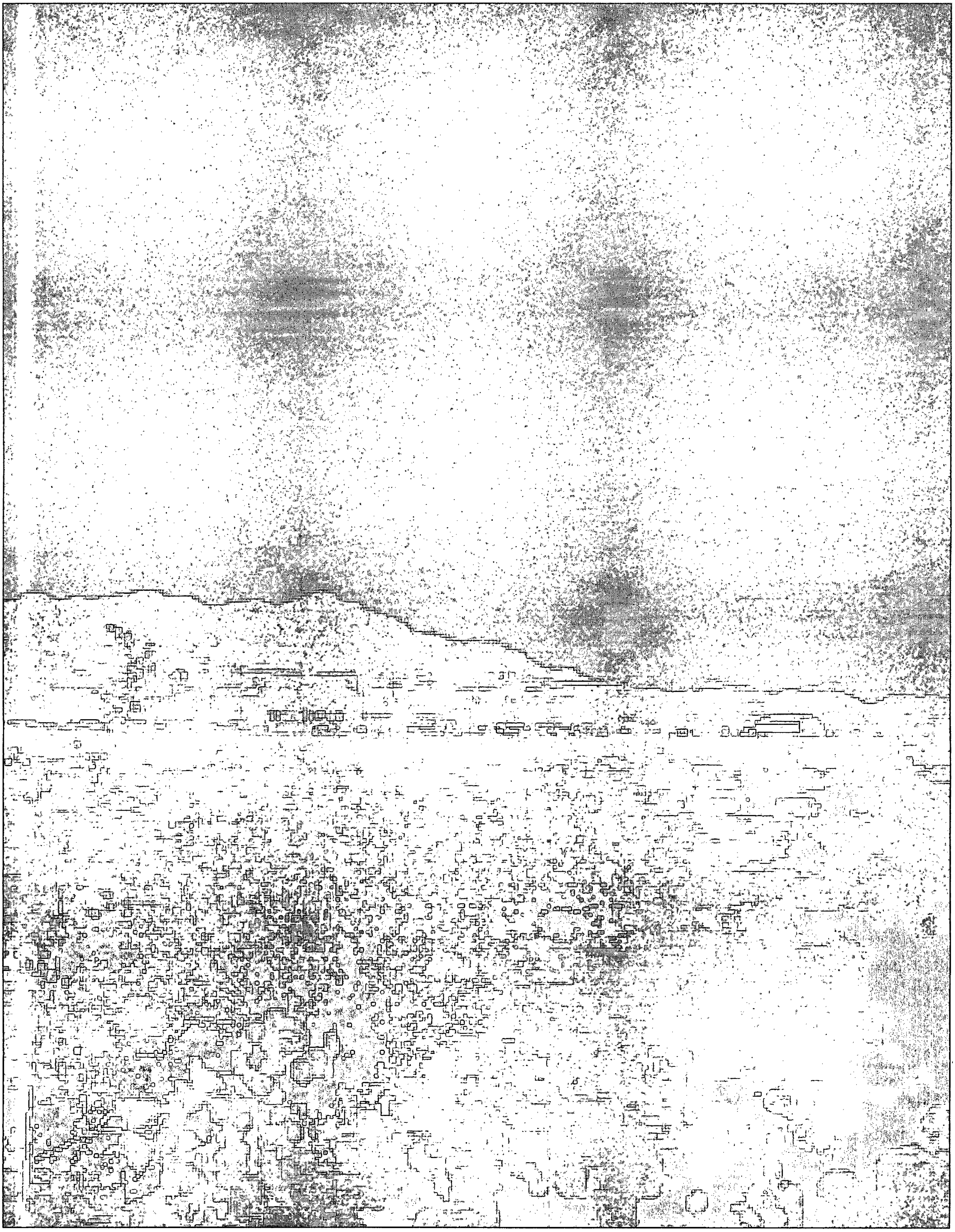
The underground mine is performing well, and the plant is embarking on a major environmental upgrade project. Unit 3's major work is scheduled for the spring of 2008.





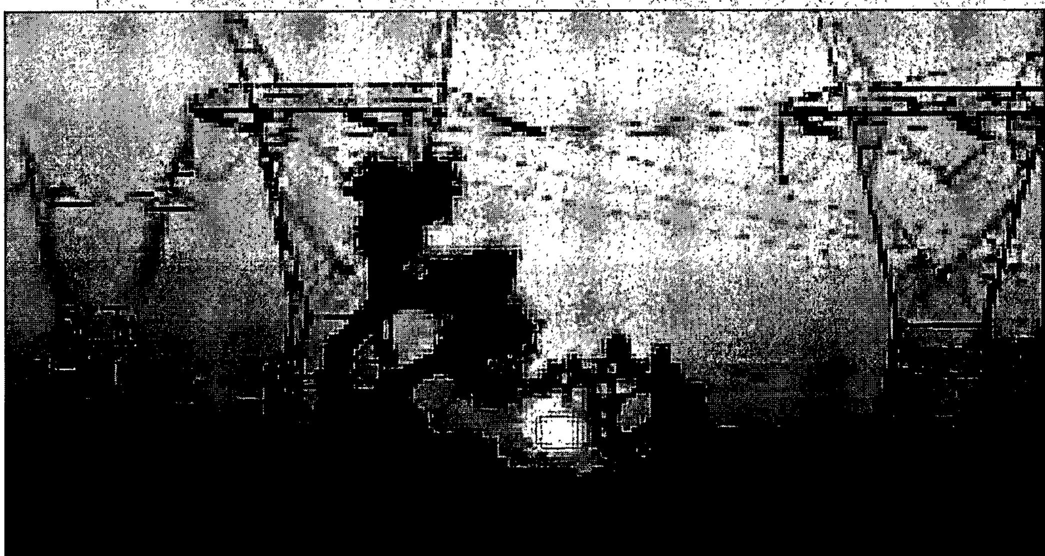
Percentage of SCPPA member participation in San Juan Project

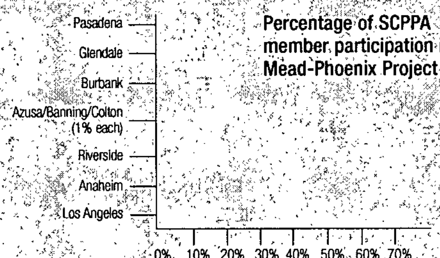




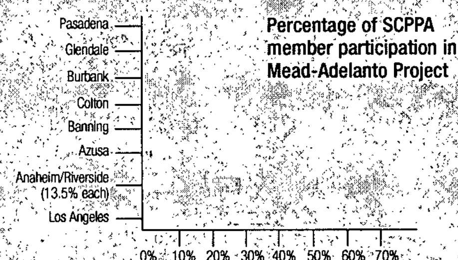
Mead-Phoenix/ Mead-Adelanto Transmission Projects

The two 500-kV transmission lines, which connect Phoenix to Las Vegas, and Las Vegas to Southern California, completed their ninth year of dependable operation for the nine SCPPA members who participate in the projects.

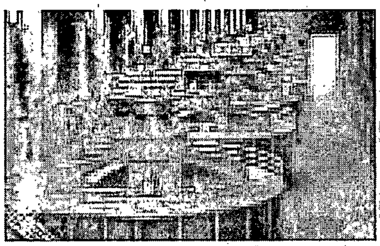




Percentage of SCPPA member participation in Mead-Phoenix Project

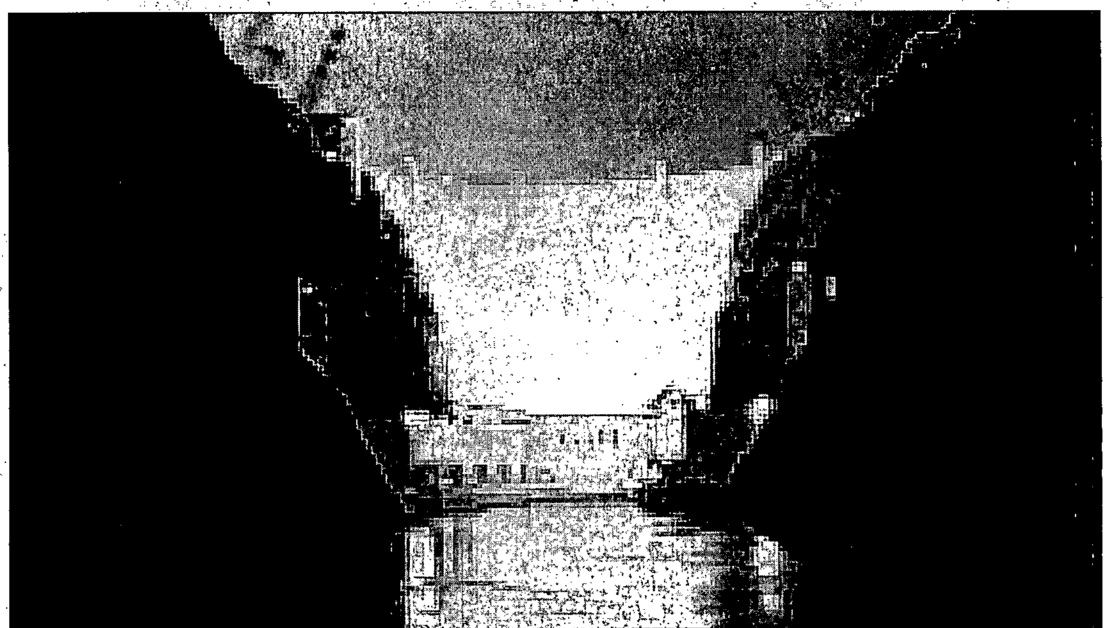


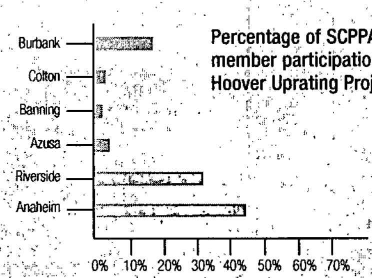
Percentage of SCPPA member participation in Mead-Adelanto Project



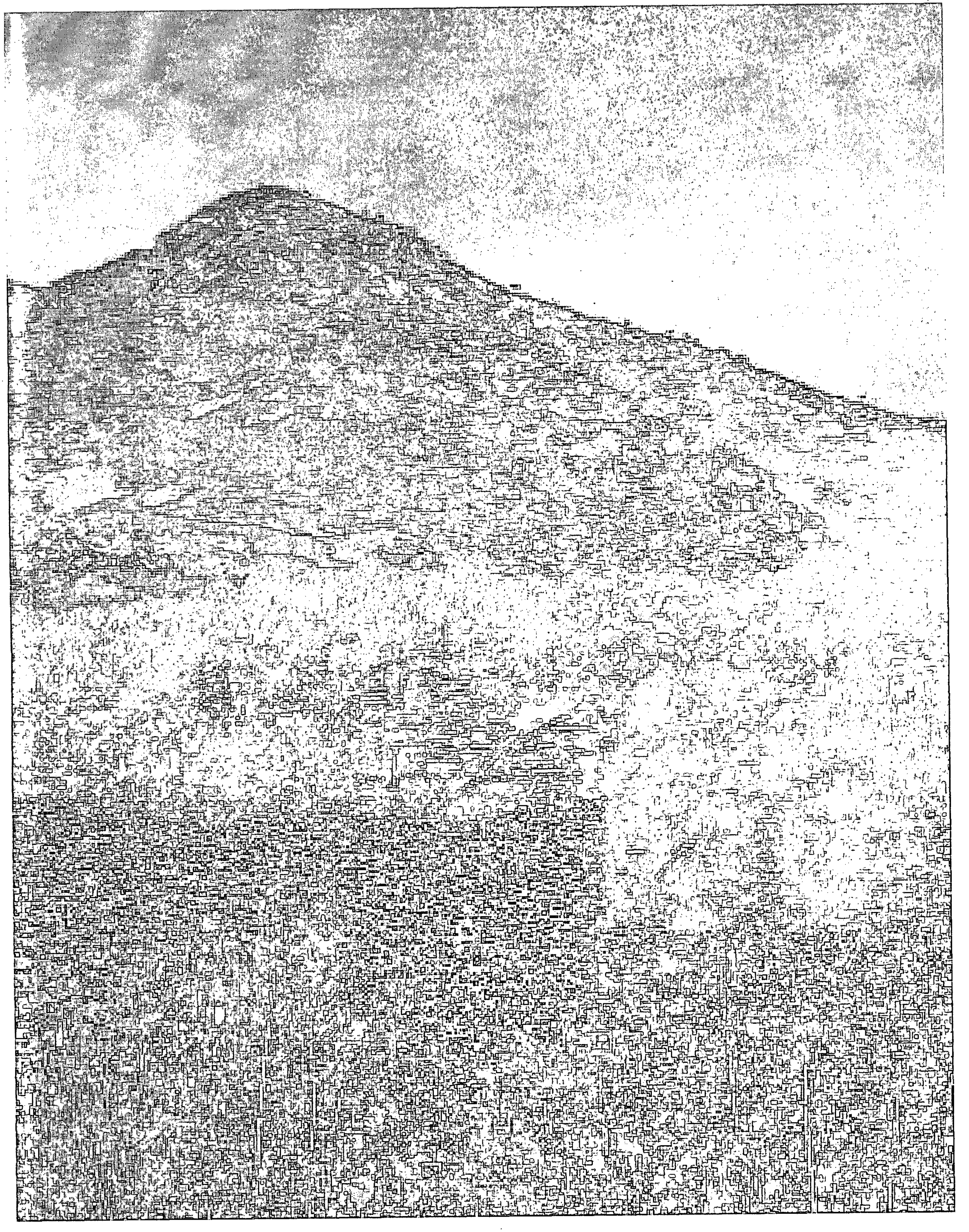
Hoover Uprating Project

The Hoover Uprating Project continues to provide six SCPPA members with low-cost, renewable energy (hydro). SCPPA is active in the development of the Lower Colorado River Multi-Species Conservation Program.



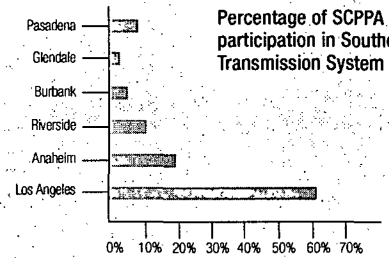


Percentage of SCPPA member participation in Hoover Uprating Project



Southern Transmission System

As usual, the STS operated with near-perfect availability (98.88%), delivering over 13.5 million MWHs to the six SCPPA members who are participants. The power comes 488 miles from the Intermountain Power Project, in Utah, over the ±500-kv DC line.

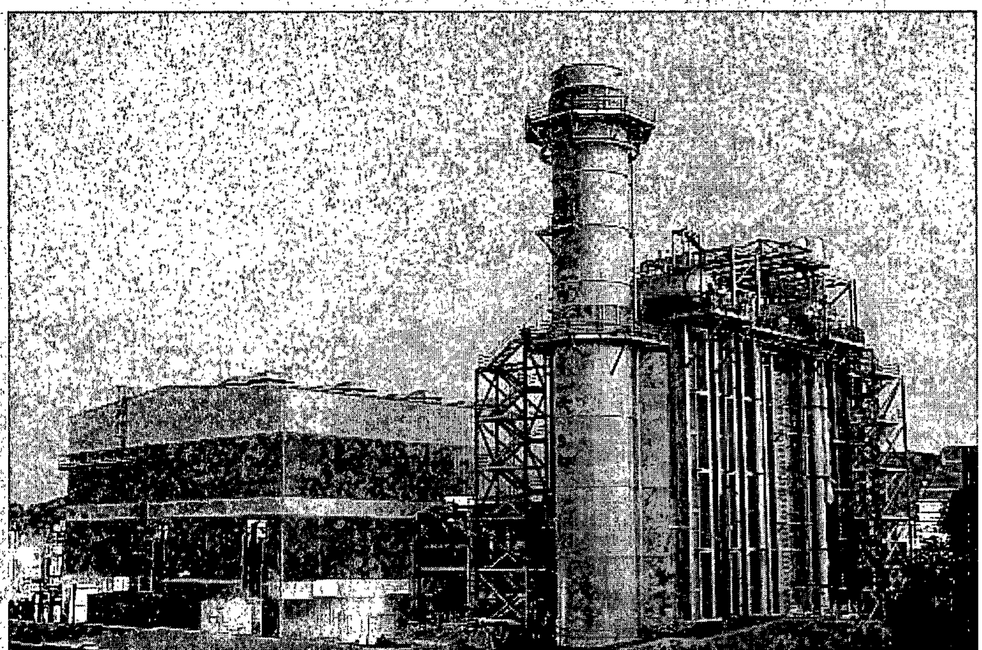


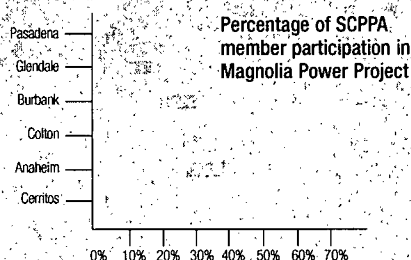
Percentage of SCPPA member participation in Southern Transmission System Project

Magnolia Power Project

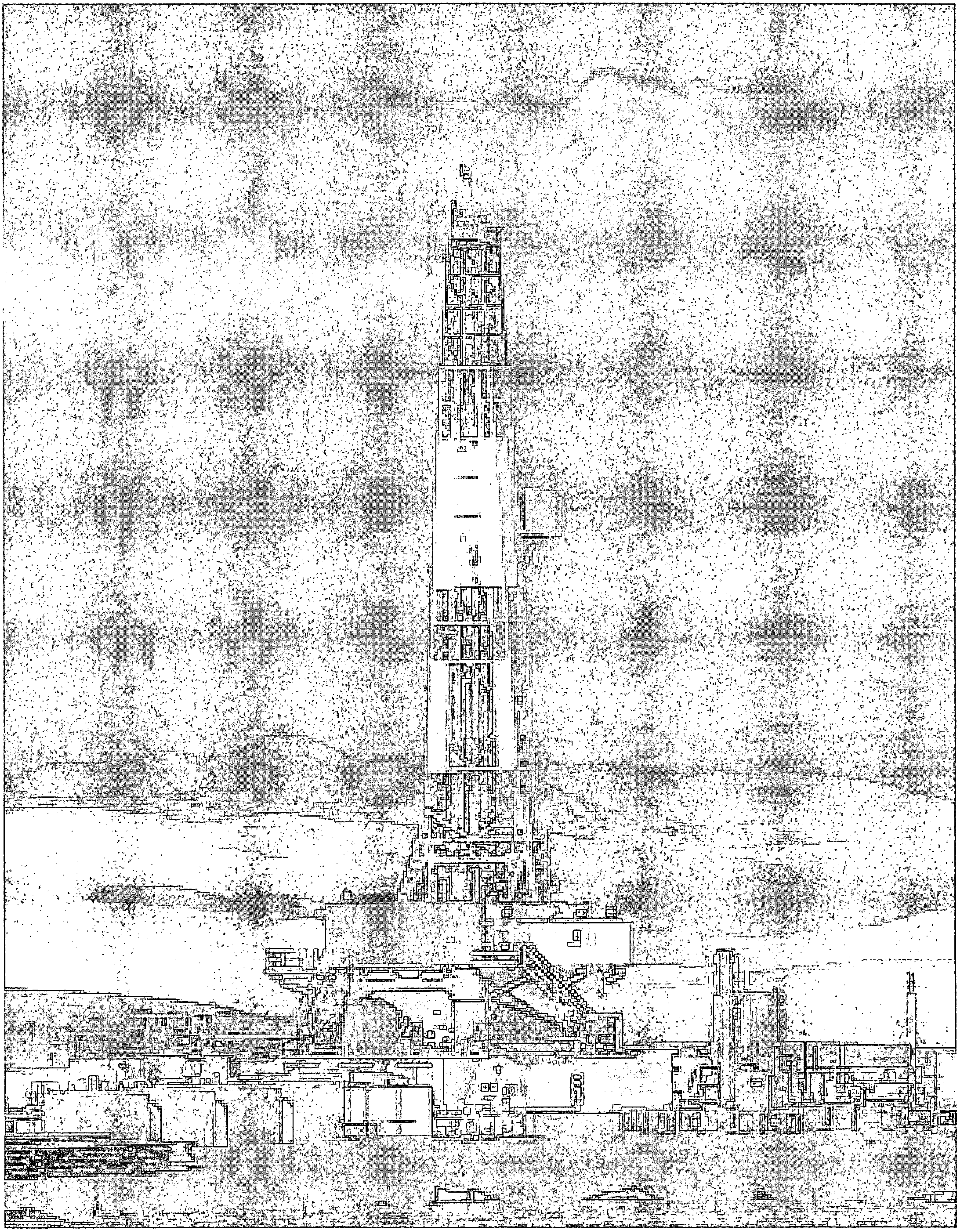
Construction was completed on the Magnolia Power Project, a 240 megawatt natural gas-fired, combined cycle plant, located on the site of an existing plant in the City of Burbank. It replaces an older, less-efficient unit. The result is more power from less fuel, with less pollution.

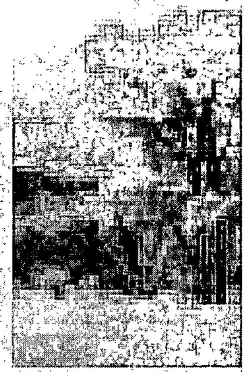
The plant reached commercial operation in September, 2005 and is the first project to be wholly-owned and operated by SCPPA members. The Participants are Anaheim, Burbank, Cerritos, Colton, Glendale, and Pasadena.





Percentage of SCPPA member participation in Magnolia Power Project

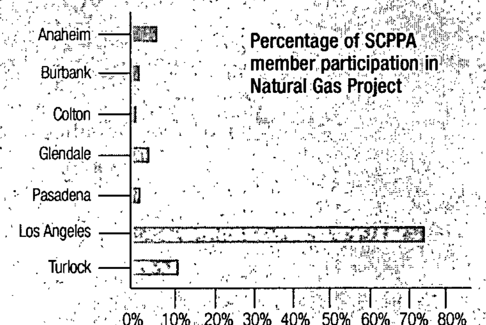




Natural Gas Project

SCPPA negotiated its first purchase of gas in the ground, with the deal closing July 1, 2005. SCPPA Members (Anaheim, Burbank, Colton, Glendale, and Pasadena) joined together with the Los Angeles Department of Water and Power and the Turlock Irrigation District* to purchase shares of existing natural gas wells in Wyoming. This purchase, along with similar future purchases, will provide a secure source of gas for the participants and hedge against volatile prices in the market.

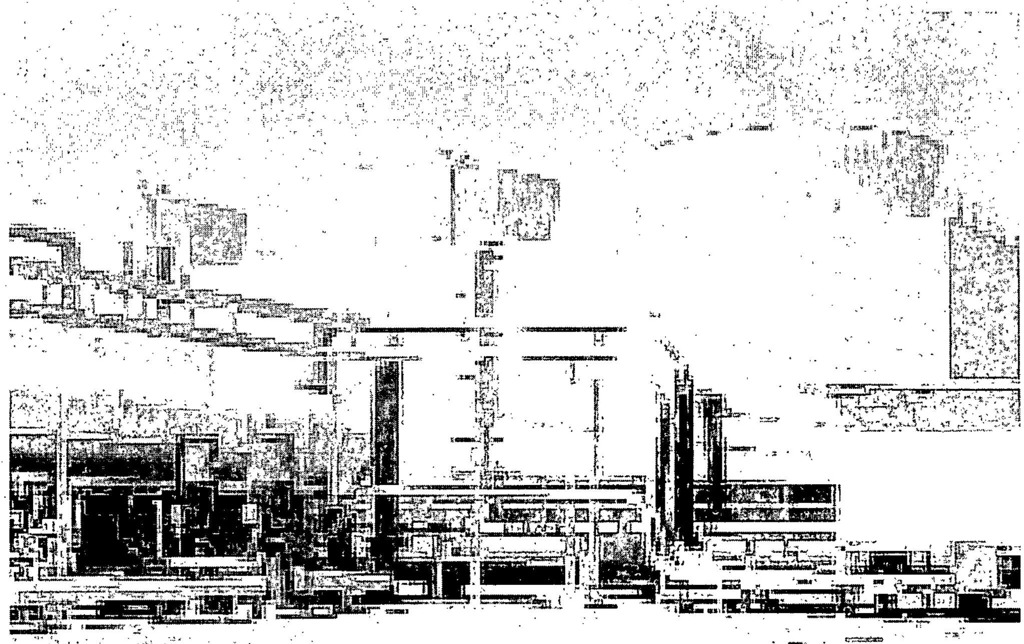
**Los Angeles and Turlock hold their interests individually. Anaheim, Burbank, Colton, Glendale, and Pasadena have ownership through SCPPA. Los Angeles serves as Project Manager for the overall project and SCPPA provides services for Los Angeles and Turlock under agency agreements.*



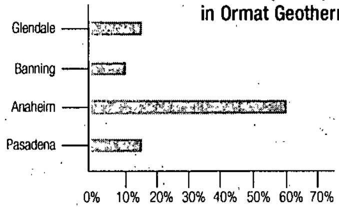
Percentage of SCPPA member participation in Natural Gas Project

Ormat Geothermal Project

SCPPA Members Anaheim, Banning, Glendale, and Pasadena began receiving a total of 10 MWs of geothermal energy from the Gould Geothermal Plant in Heber, California, on a long-term purchase contract with Ormat. An additional 10 MW is to become available soon.



Percentage of SCPPA member participation in Ormat Geothermal Project



Financing Activities

SCPPA entered into a $100 million bridge loan facility with Merrill Lynch covering a two-year period, in connection with its Natural Gas Reserves Acquisition Initiative on behalf of the financing participants (Anaheim, Burbank, and Colton). As of June 30, 2006, the draw down was approximately $28.2 million. This included $26 million for financing the Natural Gas Bonds, Series 2006-1 for the initial acquisition of natural gas reserves and other real property in Pinedale, Wyoming. This was done on behalf of the three financing members and to pay for other capital drilling costs. LADWP, Glendale, Pasadena, and the Turlock Irrigation District, the other participants in the project, completed the financing of this project totaling in excess of $300 million. Once the acquisition phase has been completed, the interim financing is expected to be replaced with permanent financing.

Other Refunding and Financial Transactions

SCPPA's Finance Committee continues to look for opportunities to lower financing costs through, for example, bond refundings and interest rate swaps. At fiscal year- end, completion financing for the Magnolia Power Project and the establishment of a Constant Maturity Swap for the Southern Transmission System 2004 Fixed Margin Swap is anticipated for July 2006.

Legislative Report

With its energy agenda focused on the environment, the California State Legislature ended its 2005-06 Session on August 31st. It considered a variety of environmental issues, ranging from solar and energy efficiency to greenhouse gases. In particular, several bills challenged the authority essential to SCPPA member cities' foundation – local control. Some of those efforts were modified, some failed and some were approved by the legislature and signed by the Governor.

Of significant importance this year was Assembly Bill 32 (AB 32), the year's major mandatory climate change bill, requiring a reduction in greenhouse gas emission to the 1990 level by 2020. Authored by Assembly Speaker Fabian Nunez, AB 32 received both national and international media attention when Governor Schwarzenegger signed the bill on September 27th. With a phase-in timeline spanning several years, AB 32 authorizes the California Air Resources Board, the California Public Utilities Commission and the California State Energy Resources Conservation and Development Commission (commonly referred to as the California Energy Commission) to establish early action emission reduction measures, establish and enforce the greenhouse gas emissions standard for all base load generation at a rate not higher than the rate for combined-cycle gas base load generation, adopt regulations greenhouse emission limits and measures to achieve maximum feasible and cost-effective reductions in greenhouse gases as well as cap and trade measures. The bill specifically applies to municipal electric utilities and becomes law on January 1, 2007.

Assembly Bill 2021 (AB 2021), as originally introduced by Lloyd Levine, the chair of the Assembly Utilities and Commerce Committee, would have authorized the California Energy Commission to enforce energy efficiency standards on municipal electric utilities, imposing a 3 cent per Kwh fine for failure to comply. Thanks to tireless negotiations and the leadership of the California Municipal Utilities Association, SCPPA members were successful in modifying the bill to encourage cost-effective energy efficiency programs. As signed by the Governor on September 29th, AB 2021 requires utilities to make energy efficiency programs a priority, specifically emphasizing municipal utility investment in all cost effective, reliable and feasible energy efficient sources of electricity. AB 2021 also requires independent verification of energy efficiency savings, a provision SCPPA consistently opposed but was unsuccessful in removing from the bill.

A multi-year effort combined with the bi-partisan cooperation of SCPPA member cities' elected officials resulted in the signature of the Governor being added to Assembly Bill 2951 (AB 2951). AB 2951 was successfully carried by a now termed-out legislator over two legislative sessions, who appeared before multiple committees and faced difficult and challenging public policy questions. AB 2951's goal of charging other public agencies the same non-discriminatory rates as all other similar customers, was viewed as persuasive by the Governor. AB 2951 settled a lengthy dispute, establishing that fees used to build power plants and distribution facilities should be borne by all customers and classes of customers. The new law, taking effect on January 1, 2007, will provide relief to non-governmental municipal utility customers by requiring government customers to pay their share of capital costs.

One of the Senate bills authored by the Senate President Pro Tempore Don Perata, Senate Bill 1368 (SB 1368), is a far more troublesome bill for SCPPA members. Signed by the Governor on September 29th with little media attention, SB 1368 prohibits all utilities from investing in power plant projects or signing contracts, including renewing existing contracts, unless the generating facilities are as clean as combined cycle gas turbine. Encroaching on municipal utilities' local control, the bill also requires the California Energy Commission (CEC) to approve municipal utility investments prior to signature. Combined efforts of SCPPA and its members seeking a better direction in the bill were not successful. Undaunted, SCPPA along with important local elected officials and representatives from the business community contacted the Governor's office, urging his veto of SB 1368. Though SB 1368's policy goal may be worthy, with California's tight electricity supply and challenged transmission system, its potential impact could quickly prove challenging for SCPPA cities as well as the Schwarzenegger administration.

With the support of SCPPA member cities, Senate Bill 1 (SB 1) was signed by the Governor on August 21st, which also represented one of his energy goals. SB 1 sets the goal at installation of 3,000 MW of photovoltaic solar energy within 10 years. SCPPA members' local governing boards have a set policy and have an established history of commitment to solar technology predating SB 1, including an aggregate total of 9,870 kW of solar photovoltaic systems within their service areas since July 1, 1997. This commitment also includes 208.1 megawatts (MW) in operation, the result of 21 solar projects owned or under contract to SCPPA and individual member cities. Most SCPPA members have also established incentives for rooftop photovoltaic systems, exceeding that required in SB 1. Nonetheless, SB 1 establishes for municipal utilities a statewide expenditure of $780 million, based on a utility's percentage of the total statewide load served by all municipal electric utilities. Securing adequate equipment supplies, due to world-wide demand, among others issues, may challenge the state in meeting the Governor's goal.

Thanks to SCPPA member cities' local elected officials, their efforts were completely successful in preventing burden-some last minute amendments from being added to Senate Bill 107 (SB 107). Failed amendments would have tied publicly owned utilities to the bill's 20% by 2010 target and, additionally, would have required large municipal utilities to own a minimum of 50% of in-state eligible renewables in order for those renewables to count toward an individual utility's goal. As it reached the Governor's desk, the bill's major provisions establish a tradable credits program for renewables and will allow local governing boards to continue to make renewable investment decisions.

Efforts to blunt the impact of the 2005 decision by the United States Supreme Court approving a Connecticut city's use of eminent domain to take private property for redevelopment of an area declared economically depressed, Senate Bill 1210 (SB 1210) was introduced to mitigate any similar action by a California city. Although utilities were not part of the problem addressed by the Supreme Court, SCPPA member cities, which rely on eminent domain, were included in the SB 1210 and opposed the bill. As signed by the Governor on September 29th, the bill imposes impediments on SCPPA members to responsibly plan for and meet future utility needs and could cause significant delay and increased costs to ratepayers.

Other bills of importance to SCPPA and its member cities include Senate Bill 1554 (SB 1554) and Senate Bill 1753 (SB 1753). Authored by Senator Debra Bowen, SB 1554 would have provided relief from costs arising from California Department of Water Resources (DWR) contracts signed at the height of the electricity crisis for residential, commercial and industrial customers who built homes and businesses on vacant property (never served by an investor-owned utility) and are now served by a municipal utility. Despite the combined efforts of the state's municipal utilities, animosity toward the bill by a member of a policy committee factored in its demise. Without SB 1554, customers who move into new residences and businesses in newly developed municipal utility territory will receive two utility bills; one from the publicly owned utility for electricity actually used and a second from the investor-owned utility for electricity never received or used. SB 1753, authored by Senator Joe Dunn, sought to assure that the repeal of the Public Utility Holding Company Act (PUHCA) in the Energy Policy Act of '05 would not place California consumers at risk. SB 1753 would have required the California Public Utilities Commission to report to the legislature on how PUHCA's loss may put California consumers at risk and recommend actions to mitigate negative impacts. On September 30th, Governor Schwarzenegger vetoed the bill, stating "the bill presupposed the repeal of PUHCA would have negative consequences... rather than the intended benefit of stimulating investment in electricity infrastructure."

In 2006, SCPPA focused its Washington, DC, efforts on: 1) updating its Congressional delegation and other policymakers on SCPPA initiatives to develop more generation and transmission; 2) advocating that public power receive comparable federal incentives to develop renewable resources; and 3) urging more cost accountability by Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs).

Since the Western energy crisis of 2000-2001, Members of the California Congressional delegation have been interested in promoting policies that would encourage development of more in-state generating resources. In that regard, SCPPA had a compelling story to tell California legislators about the unique features of the Magnolia Power Project, which came on line in 2005 and was chosen that year, in an international competition, as the "Power Plant of the Year" by Platt's Power Magazine. The Magnolia plant is "load-centered" generation located in an urban environment, is designed to use treated effluent from the City of Burbank's wastewater treatment plant, has "zero discharge" of liquids from the plant site and obtained air quality permits to operate in the Los Angeles Basin. Members of the SCPPA Congressional delegation were very receptive to information about the Magnolia Power Project and SCPPA's role in the project, because SCPPA participants dealt effectively with many environmental and "Not-In-My-Backyard" issues that challenge development of other generating resources in California. SCPPA also updated legislators on its completed purchase of natural gas reserves in Pinedale, Wyoming, to ensure a reliable fuel supply for the Magnolia Project at stable prices, not subject to gas market volatility.

The Congressional delegation was also receptive to information about SCPPA's strengthened commitment to renewable energy resources, evidenced by its recent participation in the High Winds generating project in northern California, which includes 81 state-of-the art wind turbines; in the Gould Geothermal Project in the Imperial Valley and in the Chiquita Canyon Landfill Gas-to-Energy Project in Valencia, California. SCPPA also informed legislators about potential new investments in transmission, including the "Green Path" initiative in the Imperial Valley and a proposed $60 million upgrade to the Southern Transmission System project that delivers power from the Intermountain Power Project in Utah to Southern California. With regard to RTO Accountability, SCPPA urged Members of Congress to exercise oversight of RTO/ISO operations in California and elsewhere to ensure that the organizations operate in a cost-effective manner and are accountable to consumers.

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Marcie L. Edwards
General Manager
Anaheim Public Utilities Department

Joseph F. Hsu
Director of Utilities
City of Azusa Light & Water

James Earhart
Electric Utility Director
City of Banning

Ronald E. Davis
General Manager
Burbank Water and Power

Art Gallucci
City Manager
City of Cerritos

Jeannette Olko
Utility Director
City of Colton

SCPPA Municipalities

City of Anaheim Since 1894, Anaheim Public Utilities' vision for serving customers has extended well beyond a responsibility to provide reliable, cost-effective electricity and water. Whether we are planning a new substation; building a renewable energy resource; replacing overhead electrical facilities with underground transmission, distribution and service cables; or offering new efficiency incentives, we seek long-term solutions to issues that will strengthen Anaheim's neighborhoods, schools and businesses far into the future. The business decisions we make are about providing multiple benefits that are in the best interests of our entire community. We find that outreach is a contagious philosophy as well. The more people we involve in the process, the greater our capability for turning obstacles into opportunities. We reach out to businesses to produce partnerships that create energy savings, reduce demand and save money. We team up with other City departments to increase efficiency and improve operations. We completed construction of a new, 69/12 kV distribution substation in partnership with the City's Community Services and Public Works departments. Using gas insulated switchgear technology, we built a compact switching station into a hillside, topping it off with a beautiful new park, all in the center of a developed residential neighborhood – a first of its kind in the United States. Our residential electric rates average more than 25 percent less than in surrounding cities while our Electric System revenue bond rating was raised to AA-.

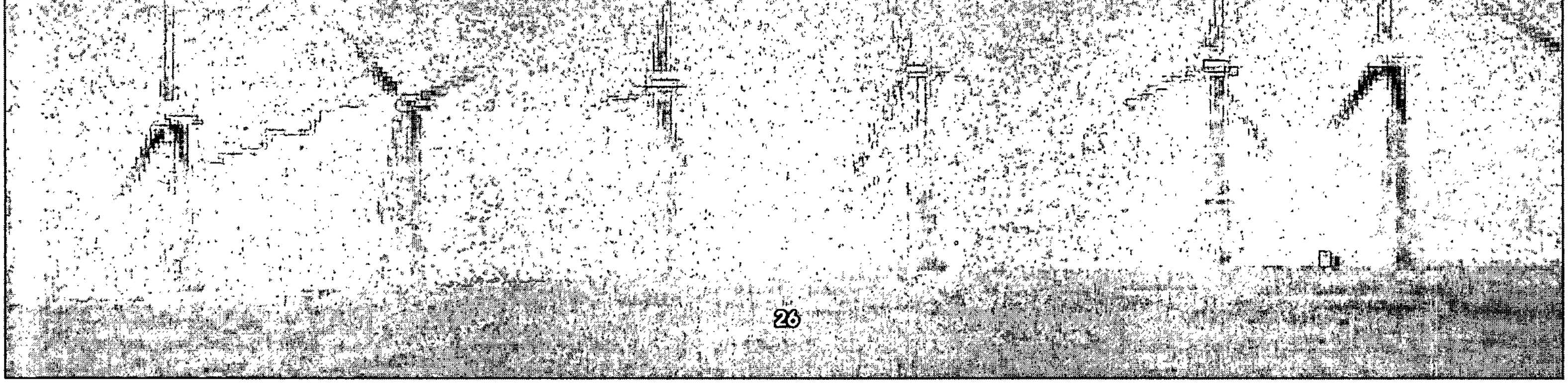
City of Azusa The City's electric utility was established in 1898 after the City purchased a private power company. The foresight and planning of those early pioneers continues to be the cornerstone of Azusa Light & Water today. It is the mission of Azusa Light & Water to provide reliable and cost effective electric and water utilities to the citizens and businesses within its service area. Azusa Light & Water continues to be proactive in promoting energy and water conservation programs to its customers, and to its future customers by continual funding of a resource conservation education programs with the local school district.

City of Banning The City of Banning Electric Utility provides electric service to more than 12,200 metered accounts covering an area of over 22 square miles. The Public Utility was established in 1922 and has an energy resource base including portions of coal, nuclear, hydro, and geothermal generating plants, which provide the majority of electricity required to meet the City's summer peak demand of 48 MW. The Utility has numerous Public Benefit programs promoting energy conservation and renewable resources. In addition, the City supports clean energy and is committed to increasing its renewable resource mix to meet and exceed its RPS requirements. The Utility is dedicated to continue providing quality service to its customers in a safe and reliable manner, at reasonable rates.

City of Burbank Burbank Water and Power (BWP) began serving both water and electric customers in 1913 and installing on-site power generation in the 1940s. BWP is committed to providing reliable electric services and safe water supply to its customers while keeping rates stable and competitive. BWP's power supply comes from a variety of resources including hydro, natural gas, coal, nuclear facilites and renewable projects throughout the West. Today, BWP operates about 135 MW of gas-fired capacity and holds 185 MW of jointly owned capacity. The most recent development at BWP is the Magnolia Power Plant, a combined cycle generating unit owned and financed through Southern California Public Power Authority (SCPPA) on behalf of its six municipal utility members. BWP is the project manager and operating agent for the Magnolia Power Project (MPP). MPP has a nominal capacity of 242 MW and a peaking capacity of 310 MW.

City of Cerritos The first new member to join Southern California Public Power Authority in over 20 years, the City of Cerritos is preparing to serve the electricity demands of its residential and business communities. To further these efforts, Cerritos is participating in the development of the Magnolia Power Project. With the goal of providing a stable and affordable supply of electricity, Cerritos intends on developing a diverse portfolio of power to be delivered as competitively and economically as possible.

City of Colton Serving a population of over 500,000 residents, Colton Electric Utility remains committed to providing our community reliable electric service and maintaining focus on the needs of our customers. We have continued to proactively offer both our business and residential customers a myriad of energy efficiency programs and low-income assistance programs. Colton Electic Utility maintains a diversified renewable resource portfolio, with energy sources of wind, landfill gas, and photovoltaic. Future renewable resources include participation in biofuel, geothermal, low head hydro, and solar thermal projects. We remain dediated to meeting our community's long term energy needs through the efforts of our stong team of employees.



Ignacio R. Troncoso
Director of Utilities
Glendale Water and Power

John M. Federowicz
Manager, Energy Department
Imperial Irrigation District

Ronald O. Vazquez
Chief Financial Officer
Los Angeles Department of Water and Power

Phyllis E. Currie
General Manager
Pasadena Water and Power

David H. Wright
Public Utilities Director
City of Riverside

City of Glendale Incorporated in 1906, Glendale purchased its electric utility in 1909, obtaining power from outside suppliers. In 1937, it began receiving power from the Hoover Dam and inaugurated the first unit of its own steam generating plant units with 250MW of gas-fired steam and combustion generating capacity. Glendale Water & Power (GWP) has a diversified portfolio that also includes coal, nuclear, and hydro generating resources, as well as a comprehensive renewables resource program in landfill gas, wind, and geothermal projects. Today, GWP provides reliable electric services to over 80,000 residential, commercial and industrial customers within a 32 square mile area. GWP continues to invest in improving the system infrastructure to ensure its long-term reliability.

Imperial Irrigation District IID entered the power industry in 1936 and today serves 128,101 customers with a peak load of 898 MW with 1,100 MW of generating resources. Among IID-owned resources are 24 MW of low head hydro units along the All American Canal, 307 MW of gas-fired steam and combined cycle units, and 162 MW of peaking gas turbines. In addition to IID's share of SCPPA resources comprising 104 MW at San Juan and 14 MW at Palo Verde, IID has 200 MW of geothermal renewable resources under long-term purchase contracts.

Los Angeles Department of Water and Power Providing service for more than a century, the Los Angeles Department of Water and Power began delivering water to the city in 1902, and with the water came power. In 1916, LADWP first delivered electicity to the city purchased from the Pasadena Municipal Plant. A year later, LADWP began generating its own hydroelectric power at the San Francisquito Power Plant No. 1. After purchasing the remaining distribution system of Southern California Edison within the city limits in 1922, LADWP became the sole water and electricity provider for the City of Los Angeles. It is now the largest municipally owned electric utility in the nation, serving a population of 4.0 million residents over a 465 square mile area. LADWP remains on firm financial footing and serves as a valuable asset to the City of Los Angeles.

City of Pasadena Pasadena Water and Power celebrated 100 years of community owned power in 2006. PWP has been providing electricity since 1906 and began delivering water to customers in 1912. The city built its first electric generating steam plant in 1907 and took over operation of its municipal street lighting from Edison Electric. In 1909, Pasadena began the extension of its operations to commercial and residential customers that resulted in the replacement of all Edison Electric service in the city by 1920. While a lot has changed over the years, PWP's strong connection to its customer/owner base remains constant. Today, PWP provides electric service to more than 61,000 metered accounts over a 23 square-mile service area at competitive rates. PWP's success is a result of its commitment to remain a valued community asset, an exceptional employer, and a partner in Pasadena's prosperous future.

City of Riverside The City of Riverside Public Utilities began serving both electric and water customers in 1883. Today we serve 104,300 metered electric customers and 63,000 metered water customers, representing a service area population of over 287,800. The utility is committed to the highest quality water and electric services at the lowest possible rates to benefit the community. To maintain their commitment, Riverside has positioned itself well in the electric market by utilizing short, mid and long-term contracts from power suppliers, and by building power generation sources within its own power grid, including a 40 MW power plant in 2002 and the completion of a 99.6 MW power plant in June 2006. Riverside's portfolio includes 27 MW of renewable resources, which includes 523 kW of photovoltaic systems within the city.

City of Vernon Vernon's Utilities Department began serving industrial customers in 1933, with completion of its diesel generating plant. In addition to its own power from diesel units and gas turbines, Vernon also receives power from Palo Verde, Hoover, and various suppliers. Vernon recently completed (October 2005) the construction of its Malburg Generating Station, a gas-fired combined cycle power plant with a net generating capacity of 134 MW. The Malburg Generating Station resides within the city limits. Vernon is part the California Independent System Operator (CAISO) Control Area and is a Participating Transmission Owner.

On the tax incentive front, SCPPA urged legislators to extend the Clean Renewable Energy Bond (CREB) program for another five years (from 2009 to 2013) and to eliminate the arbitrary $800 million cap that currently limits the availability of CREBs. The CREB program, authorized in the Energy Policy Act of 2005 (EPAct 2005), was intended to provide not-for-profit utilities with a renewable energy incentive roughly comparable to that provided under federal law to private developers. At the same time, SCPPA asked its Congressional delegation to extend the Production Tax Credit and Investment Tax Credit available for private developers of renewable resources, which will promote public-private partnerships and other arrangements whereby not-for-profit utilities can purchase renewable resources from private companies and share in the tax benefits. SCPPA also urged higher funding of the Renewable Energy Production Incentive (REPI) program, which pays a post-production incentive to qualified renewable energy projects developed by not-for-profit utilities. REPI has provided benefits to several California municipal utilities, but it requires annual appropriations and is chronically under funded. In fact, California has historically been the largest beneficiary of the program receiving 40 percent of the overall annual funding.

In July, Chairman Darryl Issa (R-CA) and Ranking Member Dianne Watson (D-CA), of the House Government Reform, Energy and Resources Subcommittee invited Pasadena's General Manager and SCPPA President Phyllis Currie to testify at a hearing on a recently-released report of the Federal Energy Regulatory Commission (FERC) on the Summer 2006 Energy Assessment, which examined resource adequacy in all regions of the country. Currie's testimony described recent resource investments by Pasadena and SCPPA and voiced concerns about the effect the Market Redesign and Technology Upgrade (MRTU) proposal that the California Independent System Operator (CAISO) filed at FERC, would have on long-term investment and reliability. In September, 2006, FERC conditionally approved the CAISO's MRTU proposal, however, SCPPA's effort and numerous letters from House and Senate members from other states in the Western Interconnection resulted in a decision by FERC that CAISO must comply with its rule on Long-Term Transmission Rights (LTTRs). SCPPA is now working with the California Municipal Utility Association and others, to highlight and propose solutions to key "seams" issues in the MRTU plan, resource adequacy requirements, as well as implementation of LTTR for load-serving entities.

SCPPA remains committed to building and acquiring generation assets for its members in an environmentally sound manner, despite continued efforts to replace the authority of local government decision-making with statutory mandates and standards. This commitment extends to each member city, which rely on local government's authority to meet electricity needs of its customers at reasonable rates and investments in renewables with an emphasis on energy efficiency, the environment and air quality.

Selected Financial Data and Statistics

Participant Ownership Interests

The Authority's participants may elect to participate in the projects. As of June 30, 2006, the members have the following participation percentages in the Authority's operating projects:

Participants	Palo Verde	STS	Hoover Uprating	Mead-Phoenix	Mead-Adelanto	San Juan	Magnolia Power Project	Natural Gas Project	Ormat Geothermal Project
City of Los Angeles	67.0%	59.5%	-	24.8%	35.7%	-	-	-	-
City of Anaheim	-	17.6%	42.6%	24.2%	13.5%	-	38.0%	35.7%	60.0%
City of Riverside	5.4%	10.2%	31.9%	4.0%	13.5%	-	-	-	-
Imperial Irrigation District	6.5%	-	-	-	-	51.0%	-	-	-
City of Vernon	4.9%	-	-	-	-	-	-	-	-
City of Azusa	1.0%	-	4.2%	1.0%	2.2%	14.7%	-	-	-
City of Banning	1.0%	-	2.1%	1.0%	1.3%	9.8%	-	-	10.0%
City of Colton	1.0%	-	3.2%	1.0%	2.6%	14.7%	4.2%	7.1%	-
City of Burbank	4.4%	4.5%	16.0%	15.4%	11.5%	-	31.0%	14.3%	-
City of Glendale	4.4%	2.3%	-	14.8%	11.1%	9.8%	16.5%	28.6%	15.0%
City of Cerritos	-	-	-	-	-	-	4.2%	-	-
City of Pasadena	4.4%	5.9%	-	13.8%	8.6%	-	6.1%	14.3%	15.0%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

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

The contracts expire as follows:

Palo Verde Project	2030
Southern Transmission System Project	2027
Hoover Uprating Project	2018
Mead-Phoenix Project	2030
Mead-Adelanto Project	2030
San Juan Project	2030
Magnolia Power Project	2036
Natural Gas Project	2030
Ormat Geothermal Project	2031

SCPPA

Combined Summary of Financial Condition and Changes in Net Assets (Deficit) (In Thousands)

	JUNE 30,		
	2006	2005	2004
Assets			
Net utility plant	$ 995,599	$ 986,292	$ 958,180
Investments	558,497	689,286	1,218,723
Cash and cash equivalents	80,778	108,240	229,983
Other	112,223	88,015	88,285
Total assets	$ 1,747,097	$ 1,871,833	$ 2,495,171
Liabilities and Net Assets (Deficit)			
Noncurrent liabilities	$ 1,806,660	$ 1,961,741	$ 2,381,299
Current liabilities	186,969	143,123	239,003
Total liabilities	1,993,629	2,104,864	2,620,302
Net assets (deficit)			
Invested in capital assets, net of related debt	(715,204)	(657,908)	(1,251,017)
Restricted net assets	361,732	332,426	1,100,972
Unrestricted net assets	106,940	92,451	24,914
Total net deficit	(246,532)	(233,031)	(125,131)
Total liabilities and net assets (deficit)	$ 1,747,097	$ 1,871,833	$ 2,495,171
Revenues, Expenses and Changes in Net Assets (Deficit)			
Operating revenues	$ 330,987	$ 220,813	$ 320,022
Operating expenses	(248,507)	(171,926)	(165,969)
Operating income	82,480	48,887	154,053
Investment income	18,932	36,631	38,423
Debt expense	(106,198)	(106,083)	(145,340)
Loss on extinguisment of debt	-	(85,827)	(508)
Change in net deficit	(4,786)	(106,392)	46,628
Net deficit – beginning of year	(233,031)	(125,131)	(126,414)
Release of over billings from prior years	-	(22,503)	-
Net contributions/withdrawals by participants	(8,715)	20,995	(45,345)
Net deficit – end of year	$ (246,532)	$ (233,031)	$ (125,131)

SCPPA Accounting and Investment Group*

From left to right: Jocelyn Mariano, Lead Utility Accountant, Margarita Felix, Utility Accountant, Alice Tong, Administrative Assistant, Therese Savery, Manager, SCPPA Accounting and Investments, Yolanda Pantig, Assistant Manager, SCPPA Accounting, Joan Ilagan, Investment Manager, and Nina Sanchez, Assistant Investment Manager.

**(Los Angeles Department of Water and Power employees assigned to SCPPA)*

CITY OF ANAHEIM

Customers - Retail	110,729
Power Generated and Purchased (in Megawatt-Hours)	
Self-Generated	929,787
Purchased	2,606,275
Total	3,536,062
Total Revenues (000s)	$336,091*
Operating Costs (000s)	$326,986*

*Unaudited

CITY OF AZUSA

Customers Served	15,524
Power Generated and Purchased (in Megawatt-Hours)	
Self-Generated	0
Purchased	253,228
Sales	
Retail	247,825
Total Revenues (000s)	$37,978*
Operating Costs (000s)	$35,826*

*Unaudited

CITY OF BANNING

Customers - Retail	12,200
Power Generated and Purchased (in Megawatt-Hours)	
Self-Generated	0
Purchased	163,644
Total	163,644
Total Revenues (000s)	$20,949*
Operating Costs (000s)	$22,245*

*Unaudited

CITY OF BURBANK

Customers - Retail	50,702
Power Generated and Purchased (in Megawatt-Hours)	
Self-Generated	80,000
Purchased	1,235,000
Total	1,315,000
Total Revenues (000s)	$187,893*
Operating Costs (000s)	$173,998*

*Excludes wholesale transactions.

CITY OF CERRITOS

Customers - Retail	24
Power Generated and Purchased (in Megawatt-Hours)	
Self-Generated	27,585
Purchased	6,804
Total	34,389
Total Revenues (000s)	$4,755*
Operating Costs (000s)	$5,010*

*Unaudited

CITY OF COLTON

Customers - Retail	18,126
Power Generated and Purchased (in Megawatt-Hours)	
Self-Generated	32,807
Purchased	351,345
Total	384,152
Total Revenues (000s)	$46,066*
Operating Costs (000s)	$49,116*

*Unaudited

CITY OF GLENDALE

Customers - Retail	83,483
Power Generated and Purchased (in Megawatt-Hours)	
Self-Generated	213,174
Purchased	1,300,393
Total	1,513,567
Total Revenues (000s)	$170,207*
Operating Costs (000s)	$183,171*

*Unaudited

IMPERIAL IRRIGATION DISTRICT

Customers Served	128,101
Power Generated and Purchased (in Megawatt-Hours)	
Self-Generated	1,043,055
Purchased	2,407,099
Total	3,450,154
Total Revenues (000s)	$403,470
Operating Costs (000s)	$345,328

LOS ANGELES DEPARTMENT OF WATER AND POWER

Customers Served	1,444,864
Power Generated and Purchased (in Megawatt-Hours)	
Self-Generated	15,043,184
Purchased	14,412,517
Total	29,455,701
Total Revenues (000s)	$2,496,389*
Operating Costs (000s)	$2,286,921*

*Unaudited

CITY OF PASADENA

Customers Served	62,139
Power Generated and Purchased (in Megawatt-Hours)	
Self-Generated	78,816
Purchased	1,559,717
Total	1,638,533
Total Revenues (000s)	$158,268
Operating Costs (000s)	$143,063

CITY OF RIVERSIDE

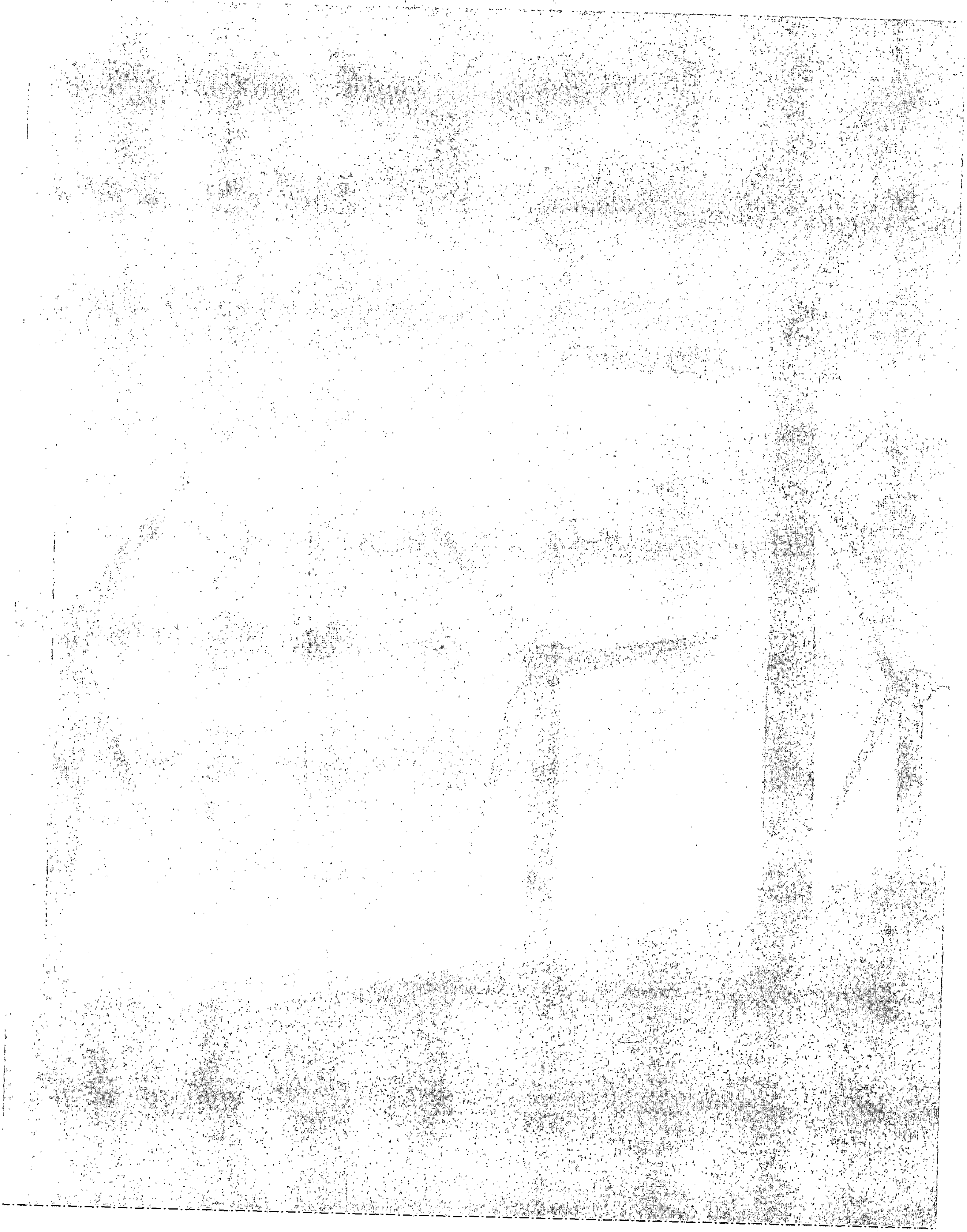
Customers Served	104,300
Power Generated and Purchased (in Megawatt-Hours)	
Self-Generated	286,000
Purchased	2,289,000
Total	2,575,000
Total Revenues (000s)	$259,188*
Operating Costs (000s)	$234,224*

*Unaudited

CITY OF VERNON

Customers Served	1,964
Power Generated and Purchased (in Megawatt-Hours)	
Self-Generated	635,848
Purchased	566,872
Total	1,202,720
Total Revenues (000s)	$110,485*
Operating Costs (000s)	$92,911*

*Unaudited



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SOUTHERN CALIFORNIA
PUBLIC POWER AUTHORITY

INDEPENDENT AUDITOR'S REPORT AND
COMBINED FINANCIAL STATEMENTS

JUNE 30, 2006 AND 2005

CONTENTS

The following discussion and analysis of the financial performance of Southern California Public Power Authority (the "Authority" or "SCPPA"), provides an overview of the Authority's financial activities for the fiscal years ended June 30, 2006 and 2005. Please read this discussion and analysis in conjunction with the Authority's Combined Financial Statements, which begin on page 24. .Description and other details pertaining to the Authority are included in the Notes to Combined Financial Statements.

The Authority is a joint powers authority whose primary purpose has been to provide joint financing for its member agencies that consist of eleven municipal electric utilities and one irrigation district in California. On a combined basis, these entities provide electricity to more than 2 million retail electric customers. A Board of Directors (the "Board") governs the Authority, which consists of one representative from each member agency.

The Authority has interests in the following projects:

PALO VERDE PROJECT

On August 14, 1981, the Authority purchased a 5.91% interest in the Palo Verde Nuclear Generating Station ("PVNGS"), a 3,810 megawatt nuclear-fueled generating station near Phoenix, Arizona, a 5.56% ownership interest in the Arizona Nuclear Power Project High Voltage Switchyard, and a 6.55% share of the right to use certain portions of the Arizona Nuclear Power Project Valley Transmission System (collectively, the "Palo Verde Project"). Units 1, 2 and 3 of the Palo Verde Project began commercial operations in January 1986, September 1986, and January 1988, respectively.

SOUTHERN TRANSMISSION SYSTEM PROJECT

On May 1, 1983, the Authority entered into an agreement with the Intermountain Power Agency ("IPA") to defray all the costs of acquisition and construction of the Southern Transmission System Project ("STS"), which provides for the transmission of energy from the Intermountain Generating Station in Utah to Southern California. STS commenced commercial operations in July 1986. The Department of Water and Power of the City of Los Angeles ("LADWP"), a member of the Authority, serves as project manager and operating agent of the Intermountain Power Project ("IPP").

HOOVER UPRATING PROJECT

As of March 1, 1986, the Authority and six participants entered into an agreement pursuant to which each participant assigned its entitlement to capacity and associated firm energy to the Authority in return for the Authority's agreement to make advance payments to the United States Bureau of Reclamation ("USBR") on behalf of such participants. The Authority has an 18.68% interest in the contingent capacity of the Hoover Uprating Project ("HU").

MEAD-PHOENIX AND MEAD-ADELANTO PROJECTS

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

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

MULTIPLE PROJECT FUND

During fiscal year 1990, the Authority issued Multiple Project Revenue Bonds for net proceeds of approximately $600 million to provide funds to finance costs of construction and acquisition of ownership interests or capacity rights in one or more, then unspecified, projects for the generation or transmission of electric energy. Certain of these funds were used to finance the Authority's interests in Mead-Phoenix and Mead-Adelanto.

SAN JUAN PROJECT

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

MAGNOLIA POWER PROJECT

In March 2003, the Authority received approval from the California Energy Commission for construction of the Magnolia Power Project. The Project consists of a combined cycle natural gas-fired generating plant with a nominally rated net base capacity of 242 megawatts and was built on a site in the City of Burbank, California. The plant is the first that is wholly owned by the Authority and entitlements to 100% of the capacity and energy of the Project have been sold to six of its members. The City of Burbank, a Project participant, managed its construction and also serves as the Operating Agent for the Project. Commercial operations began September 22, 2005.

NATURAL GAS PROJECT

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

ORMAT GEOTHERMAL PROJECT

The Authority entered into long-term Power Purchase Agreements in December 2005 with divisions of Ormat Technologies, Inc. for 20 megawatts ("MW") of electric generation from geothermal energy facilities located in Heber, California. The Project started delivery of 10 MW in January 2006 and is expected to receive additional deliveries in December 2007. The City of Anaheim acts as the Scheduling Coordinator on behalf of the Project Participants.

PROJECTS' STABILIZATION FUND

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

PARTICIPANT OWNERSHIP INTERESTS

The Authority's participants may elect to participate in the projects. As of June 30, 2006, the members have the following participation percentages in the Authority's operating projects:

Participants	Palo Verde	STS	Hoover Uprating	Mead-Phoenix	Mead-Adelanto	San Juan	Magnolia Power Project	Natural Gas Project	Ormat Geo-thermal Project
City of Los Angeles	67.0%	59.5%	-	24.8%	35.7%	-	-	-	-
City of Anaheim	-	17.6%	42.6%	24.2%	13.5%	-	38.0%	35.7%	60.0%
City of Riverside	5.4%	10.2%	31.9%	4.0%	13.5%	-	-	-	-
Imperial Irrigation District	6.5%	-	-	-	-	51.0%	-	-	-
City of Vernon	4.9%	-	-	-	-	-	-	-	-
City of Azusa	1.0%	-	4.2%	1.0%	2.2%	14.7%	-	-	-
City of Banning	1.0%	-	2.1%	1.0%	1.3%	9.8%	-	-	10.0%
City of Colton	1.0%	-	3.2%	1.0%	2.6%	14.7%	4.2%	7.1%	-
City of Burbank	4.4%	4.5%	16.0%	15.4%	11.5%	-	31.0%	14.3%	-
City of Glendale	4.4%	2.3%	-	14.8%	11.1%	9.8%	16.5%	28.6%	15.0%
City of Cerritos	-	-	-	-	-	-	4.2%	-	-
City of Pasadena	4.4%	5.9%	-	13.8%	8.6%	-	6.1%	14.3%	15.0%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

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

The contracts expire as follows:

Palo Verde Project	2030
Southern Transmission System Project	2027
Hoover Uprating Project	2018
Mead-Phoenix Project	2030
Mead-Adelanto Project	2030
San Juan Project	2030
Magnolia Power Project	2036
Natural Gas Project	2030
Ormat Geothermal Project	2031

CRITICAL ACCOUNTING POLICIES

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

Investment Policy and Controls - The Authority's investment function operates within a legal framework established by Sections 6509.5 and 53600 et. seq. of the California Government Code, Indentures of Trust, instruments governing financial arrangements entered into by the Authority to finance and operate Projects, and the Authority's Investment Policy. The Indentures of Trust authorize the establishment of specific Project funds and accounts, specify how monies are to be applied, and name third party Trustees.

Funds available for investment include proceeds from bonds and notes sales, payments from the participants, maturities of previous investments, earnings, exchanges of securities and interest from swap agreements. Funds are managed and invested separately and principal and earnings are credited and allocated to designated funds or accounts as outlined in each Project's Indenture of Trust, or in the Projects' Stabilization Fund which was established by a Board Resolution.

The three fundamental criteria in the investment program, ranked in accordance of importance, are: safety of principal, liquidity, and return. An exception to the preceding criteria is made for the Palo Verde Nuclear Decommissioning Trust Funds, as liquidity will not be a factor until 2023. The investment criteria for the Decommissioning Trust Funds, in order of importance, are as follows: safety, return, and liquidity.

Debt Management Program - The Authority's financing goal is to obtain the lowest prudent rates of interest on debt issues and to issue debt in the most cost-effective manner. In addition, the Authority will continue to utilize debt management strategies that reduce the overall cost of borrowing for its members. In general, the Authority issues new money debt and refunding debt on either a negotiated or competitive basis as determined by the Board. A minimum net present value savings of 5%, as a percent of the refunded par amount, is the general target when determining the potential to refund existing Authority debt. The Authority may also use interest rate swaps or other derivative products to help meet important financial objectives.

CRITICAL ACCOUNTING POLICIES (Continued)

Jointly Owned Utility Plant - The Authority owns interests in several generating stations, transmission systems, and gas reserve leases. Under these arrangements, a participating member has an undivided interest in a utility plant and is responsible for its proportionate share of the costs of construction and operation and is entitled to its proportionate share of the energy produced. All utility plant of the Authority, with the exception of the Magnolia Power Project, is jointly owned. The related cost and accumulated depreciation for these jointly-owned projects has been reflected in each project's financial statements in utility plant. Additionally, the Authority's share of expenses for each project is included in the statements of revenues, expenses, and changes in net assets (deficit) as part of operations and maintenance expenses.

USING THIS FINANCIAL REPORT

This annual financial report consists of a series of financial statements and reflects the self-supporting activities of the Authority that are funded primarily through the sale of energy, natural gas, and transmission services to member agencies under project specific "take or pay" contracts that require each member agency to pay its proportionate share of operating and maintenance expenses and debt service with respect to such projects.

Combined Financial Statements - The Combined Financial Statements, using an accrual basis of accounting, provide an indication of the Authority's financial health. The Combined Statements of Net Assets (Deficit) include all of the Authority's assets and liabilities, 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 Combined Statements of Revenues, Expenses and Changes in Net Assets (Deficit) report all of the revenues and expenses during the time periods indicated. The Combined Statements of Cash Flows report the cash provided and used by operating activities, as well as other cash sources such as investment income, cash payments for bond principal payments, and capital additions and betterments.

Combined Financial Statements (Continued)
Combined Summary of Financial Condition and Changes in Net Assets (Deficit)
(In Thousands)

	JUNE 30,		
	2006	2005	2004
Assets			
Net utility plant	$ 995,599	$ 986,292	$ 958,180
Investments	558,497	689,286	1,218,723
Cash and cash equivalents	80,778	108,240	229,983
Other	112,223	88,015	88,285
Total assets	$ 1,747,097	$ 1,871,833	$ 2,495,171
Liabilities and Net Assets (Deficit)			
Noncurrent liabilities	$ 1,806,660	$ 1,961,741	$ 2,381,299
Current liabilities	186,969	143,123	239,003
Total liabilities	1,993,629	2,104,864	2,620,302
Net assets (deficit)			
Invested in capital assets, net of related debt	(715,204)	(657,908)	(1,251,017)
Restricted net assets	361,732	332,426	1,100,972
Unrestricted net assets	106,940	92,451	24,914
Total net deficit	(246,532)	(233,031)	(125,131)
Total liabilities and net assets (deficit)	$ 1,747,097	$ 1,871,833	$ 2,495,171
Revenues, Expenses and Changes in Net Assets (Deficit)			
Operating revenues	$ 330,987	$ 220,813	$ 320,022
Operating expenses	(248,507)	(171,926)	(165,969)
Operating income	82,480	48,887	154,053
Investment income	18,932	36,631	38,423
Debt expense	(106,198)	(106,083)	(145,340)
Loss on extinguisment of debt	-	(85,827)	(508)
Change in net deficit	(4,786)	(106,392)	46,628
Net deficit - beginning of year	(233,031)	(125,131)	(126,414)
Release of over billings from prior years	-	(22,503)	-
Net contributions/withdrawals by participants	(8,715)	20,995	(45,345)
Net deficit - end of year	$ (246,532)	$ (233,031)	$ (125,131)

Combined Financial Statements (Continued)

Net Deficit -

During fiscal year 2006, the Authority's net deficit increased by $14 million, mainly due to the decrease in assets of $125 million and the decrease in liabilities of $111 million.

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

- Utility Plant - increased by $9 million.
  This increase is the net effect of the acquisition of natural gas reserves, capital expenditures in the Natural Gas Project, and construction in the Magnolia Power Project offset by scheduled depreciation in other projects.

- Investments - decreased by $131 million.
  This decrease is primarily due to the use of funds for the redemption of $162.1 million in Multiple Project revenue bonds on July 1, 2005; a principal payment of $11.3 million for the Palo Verde Project on June 7, 2006; a $4.3 million draw down from the FSA investment agreement in the Palo Verde Project, which provides for withdrawals of guaranteed investment coupons through June 2017 to pay for notes owed to the participants; and capital expenditures for the Magnolia Power Project.

  - These decreases were offset by an increase of $14 million in participant billings for the Mead Phoenix and Mead Adelanto Projects for debt service payments in 2007; an $18 million increase in the purchase of investments with longer maturity yields over short-term maturities to set aside funds for debt service payments for STS; and $8 million of San Juan over billings for fiscal years 2005 and 2006, which have been authorized to be accumulated for anticipated environmental upgrades in 2008.

- Cash and cash equivalents – decreased by $27 million.
  This decrease is primarily due to the use of the funds from the Project Stabilization Fund to acquire the natural gas reserve leases on July 1, 2005 (Glendale and Pasadena deposited $13 million and $6.5 million, respectively, on June 30, 2005); the reallocation of investments from short term to long term in STS; and $12 million of short term securities purchased in the newly acquired Ormat and Natural Gas Projects.

Combined Financial Statements (Continued)

- Other Assets – increased by $24 million.
  This increase is primarily due to the $9.9 million recognition of spare parts inventory in the Magnolia Power Project. In addition, increases in accounts receivable were recognized in Palo Verde, Magnolia Power, and Natural Gas Projects. Increase in Palo Verde's billings of $6.5 million mainly due to higher maintenance expense and lower interest earnings allocated to debt service this fiscal year. Accounts receivable in Magnolia Power Project increased by $2.0 million for outstanding fuel billings, and Natural Gas recorded accounts receivable of $4.4 million for outstanding capital billings, gas, and oil sales to Coral Energy and Ultra Resources.

The decrease in the Authority's liabilities of $111 million is primarily the net effect of the redemption of the Multiple Project revenue bonds; an increase in the Authority's liabilities for the financing of the Natural Gas reserve acquisition on behalf of Project A participants (Anaheim, Burbank, and Colton); and an increase in the advances due to the Participants of the Magnolia Power and Natural Gas Projects.

During fiscal year 2005, a significant amount of the Palo Verde bonds were legally defeased on July 1, 2004 as part of the Authority's completion of the Restructuring Plan (See Note 5). As a result of the completion of this plan, long-term investments decreased by $529 million, cash and cash equivalents and other decreased by $122 million, and liabilities decreased by $515 million. In addition, because of the net effect of the continued construction of the Magnolia Power Plant and the accumulated depreciation of other projects, the utility plant increased by $28 million.

Net Operating Income -

During fiscal year 2006, the net increase in operating income of $34 million is due to the following:

- Increase of $14 million in participant billings in Mead-Adelanto and Mead-Phoenix projects for debt service payments during the year ended June 30, 2006. Mead-Adelanto and Mead-Phoenix are scheduled to pay principal of $10.8 million and $3.2 million, respectively, relating to the 2004 Series A bonds.

- Recognition of net operating income of $1.5 million this fiscal year relating to the start-up of the natural gas reserve leases.

- Net operating income of $6.5 million recognized since the Magnolia Power Plant began commercial operation on September 22, 2005.

- Increase of $8.4 million in participant billings recorded in the Palo Verde Project as of June 30, 2006, mainly as the result of higher maintenance expense due to the replacement of steam generators in Palo Verde Unit 1 and lower interest earnings allocated to debt service.

Combined Financial Statements (Continued)

During fiscal year 2005, operating income decreased by $105 million primarily due to lower debt service requirements because of the completion of the Palo Verde Restructuring Plan

Investment Income -

During fiscal year 2006, investment income decreased by $18 million due to the following:

- Use of $162.1 million in funds on July 1, 2005 to redeem the callable Multiple Project revenue bonds.

- Market value of Palo Verde Project's Decommissioning funds decreased by $3.5 million due to interest rate increases over the past twelve months resulting in the decline of the market value of securities purchased before that period.

Debt Expense -

During fiscal year 2005, the decrease in debt expenses of $39 million was largely due to the decrease in interest expense, amortization of bond discounts and loss on refunding related to the defeasance of the 1987A, 1989A, and the 1997B Palo Verde bonds on July 1, 2004.

Loss on Extinguishment of Debt -

The $85 million Loss on Extinguishment of Debt resulted from the defeasance of the remaining 1987A, 1989A, and 1997B Palo Verde bonds on July 1, 2004. This consists of the write-off of the remaining unamortized debt expenses relating to those issues as of the date of extinguishment and the adjustments made to market value of the related investments which were recorded as of June 30, 2004.

Supplementary Information -

During fiscal year 2005, $22 million of Palo Verde accumulated over billings from prior years was reclassified from cost recoverable to notes payable. The Board of Directors authorized these funds to be released to the participants to pay a portion of the operating and maintenance expenses of the Palo Verde Project.

During fiscal year 2005, cities of Glendale and Pasadena contributed a combined total of $20 million in cash for their portion of the purchase of the Natural Gas leases which were acquired on July 1, 2005.

Combined Financial Statements (Continued)

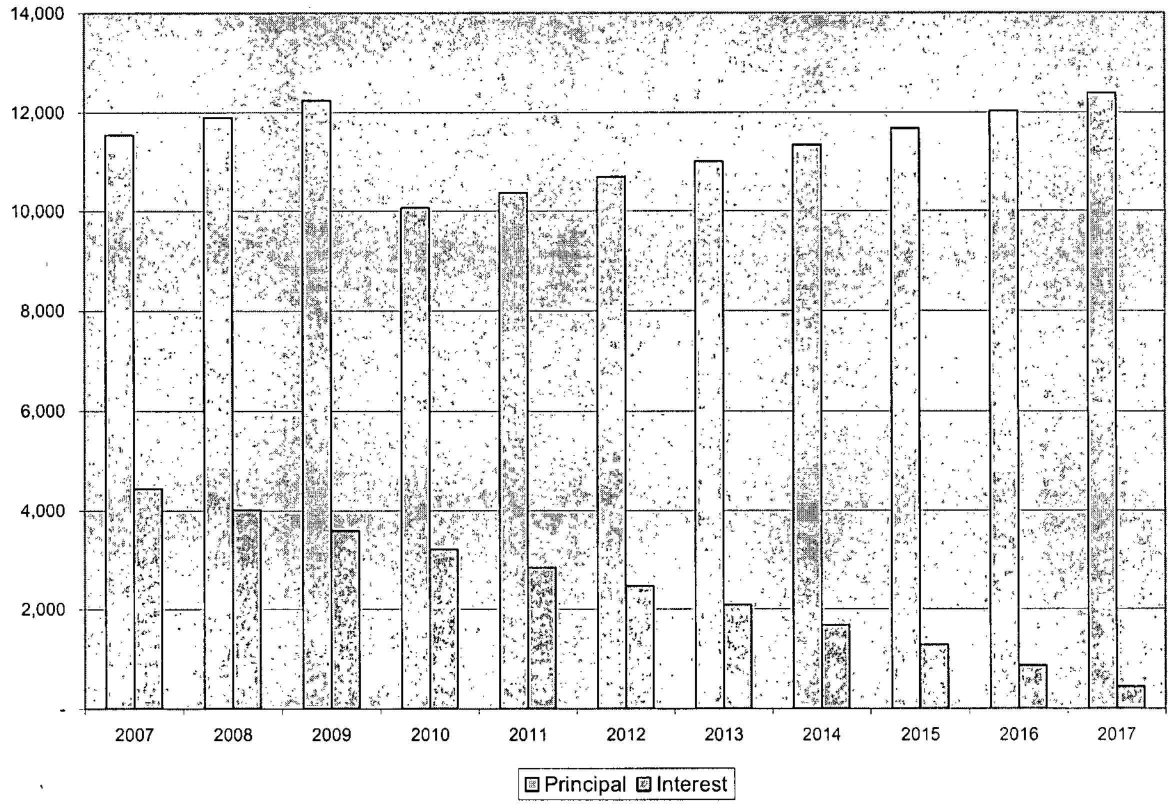
Long-Term Debt - The Authority has financed the acquisition of most of its Projects through the issuance of revenue bonds. The exception is the Natural Gas Project wherein some of the natural gas participants used cash for their percentage of the acquisition. Capital additions to all of these Projects are financed through revenues received from the Participants.

In May 2005, the Authority issued new refunding bonds for San Juan as follows:

Description of Bonds	Par Amount of Refunded Bonds	Par Amount of Refunding Issue	Debt Service Savings	Net Present Value Savings	Bond Ratings by S&P/Moody's
San Juan Project Revenue Bonds 2005 Refunding Series A	$ 71,850,000	$ 71,880,000	$ 10,026,571	$ 6,669,244	AAA/Aaa

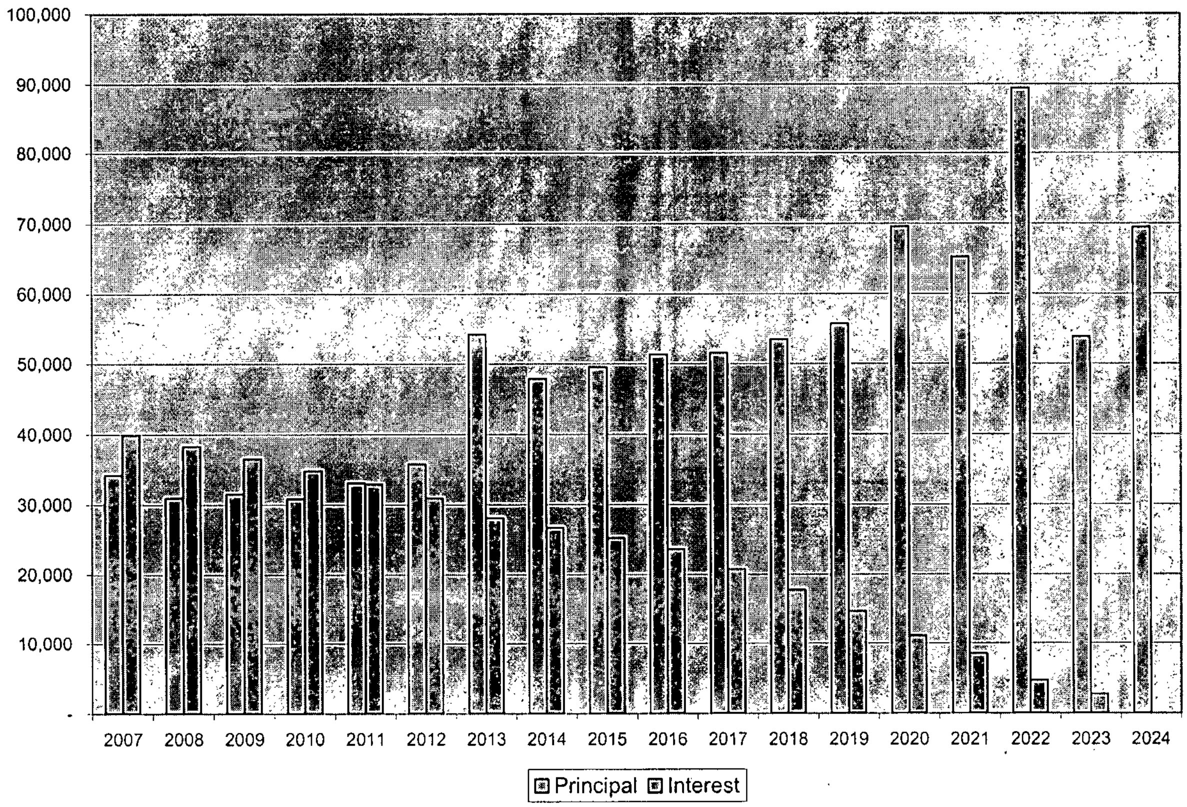
The following graphs for each of the Authority's Projects provide an indication of the principal and interest payments on the bonds that are due each year following June 30, 2006 until the bonds mature. Interest is reflected on an accrual basis.

PALO VERDE PROJECT
Debt Service Requirements
Fiscal Year Ending June 30, 2006 ($ in thousands)



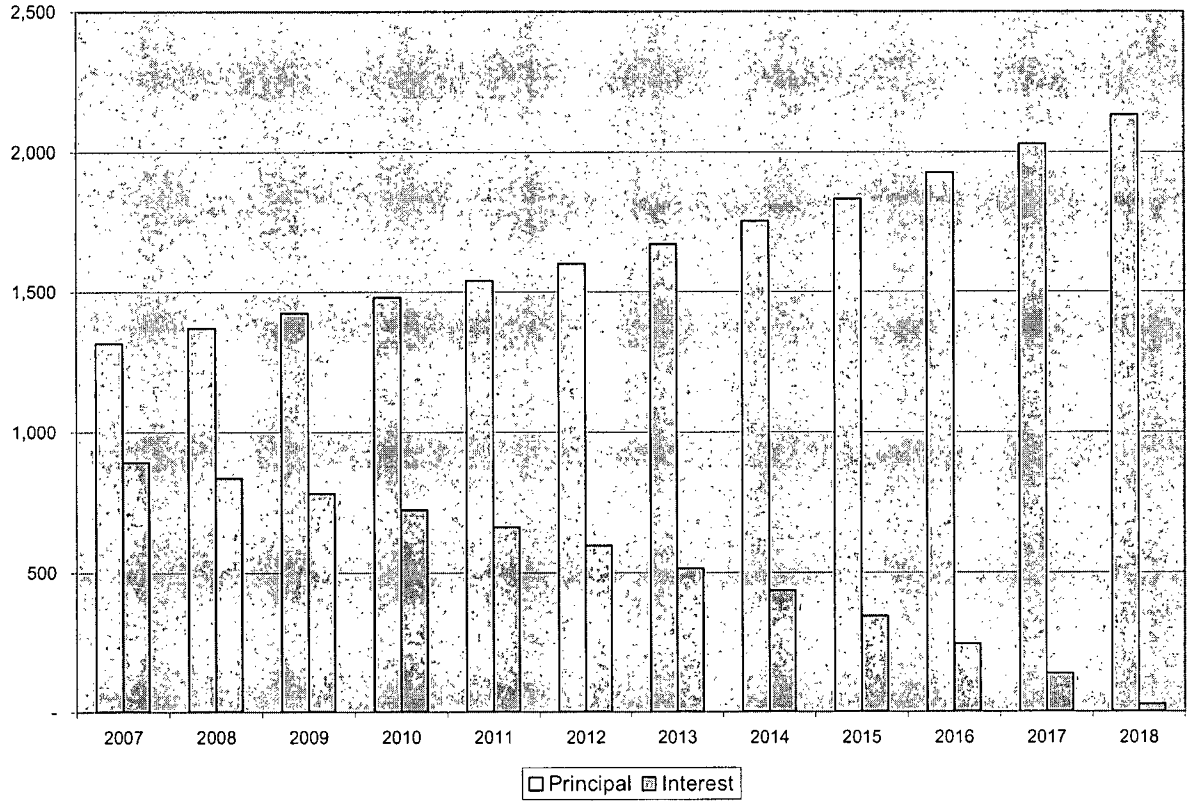
Interest payments on the remaining bonds are payable on the first Wednesday of each month. Principal maturity of $11.3 million was paid on June 7, 2006. The bonds mature in the fiscal year ended June 30, 2017.

SOUTHERN TRANSMISSION SYSTEM PROJECT
Debt Service Requirements
Fiscal Year Ending June 30, 2006 ($ in thousands)



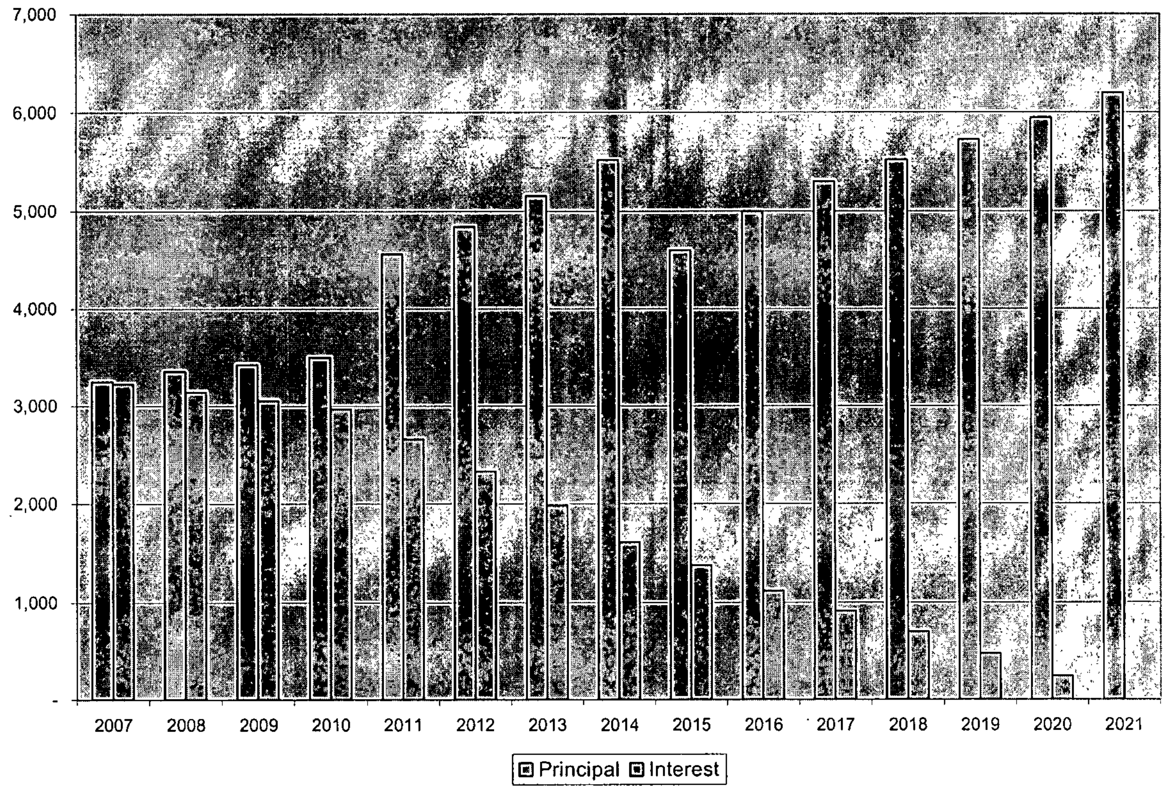
Fixed interest on the bonds is paid semi-annually on July 1 and January 1 of each year. Variable interest is paid monthly, except for the 2003A bonds, which is paid weekly. Principal maturities of $31.5 million were paid on July 1, 2005. The bonds mature in the fiscal year ended June 30, 2024.

HOOVER UPRATING PROJECT
Debt Service Requirements
Fiscal Year Ending June 30, 2006 ($ in thousands)



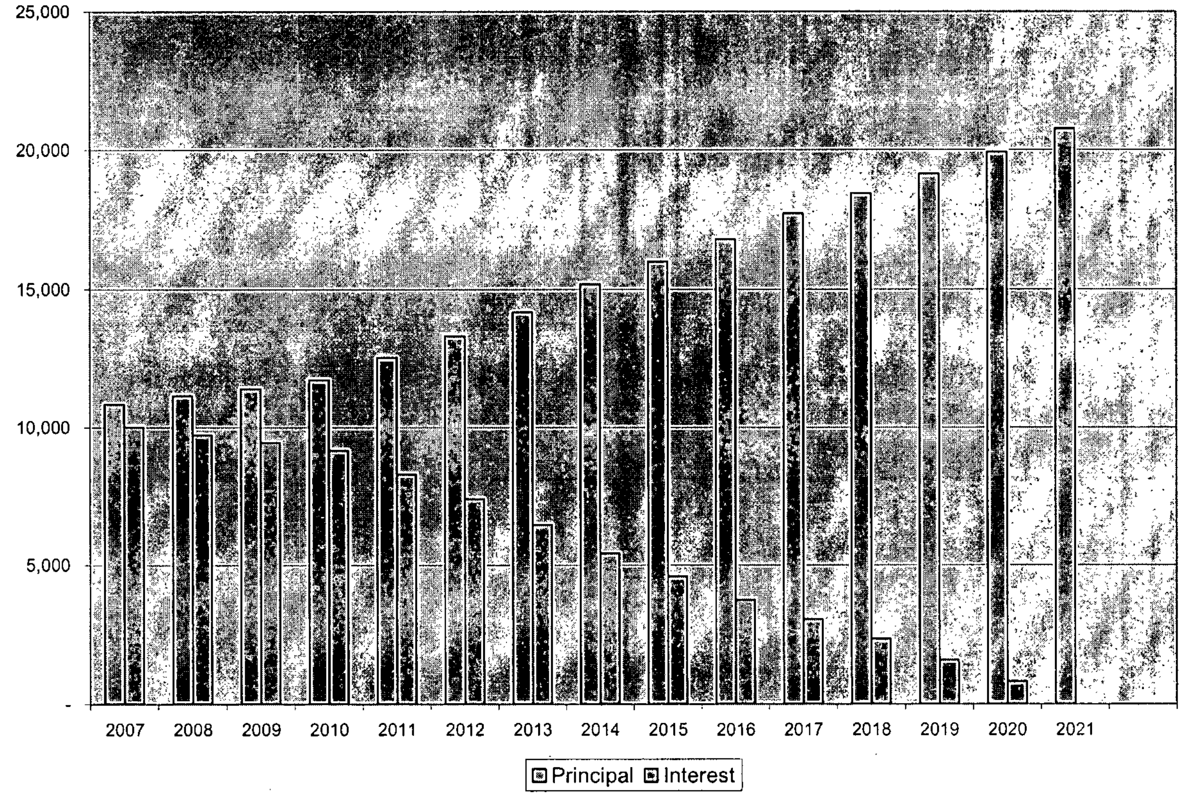
Interest payments on the bonds are payable semi-annually on October 1 and April 1 of each year. Principal maturities of $1.3 million were paid on October 1, 2005. The bonds mature in the fiscal year ended June 30, 2018.

MEAD-PHOENIX PROJECT
Debt Service Requirements
Fiscal Year Ending June 30, 2006 ($ in thousands)



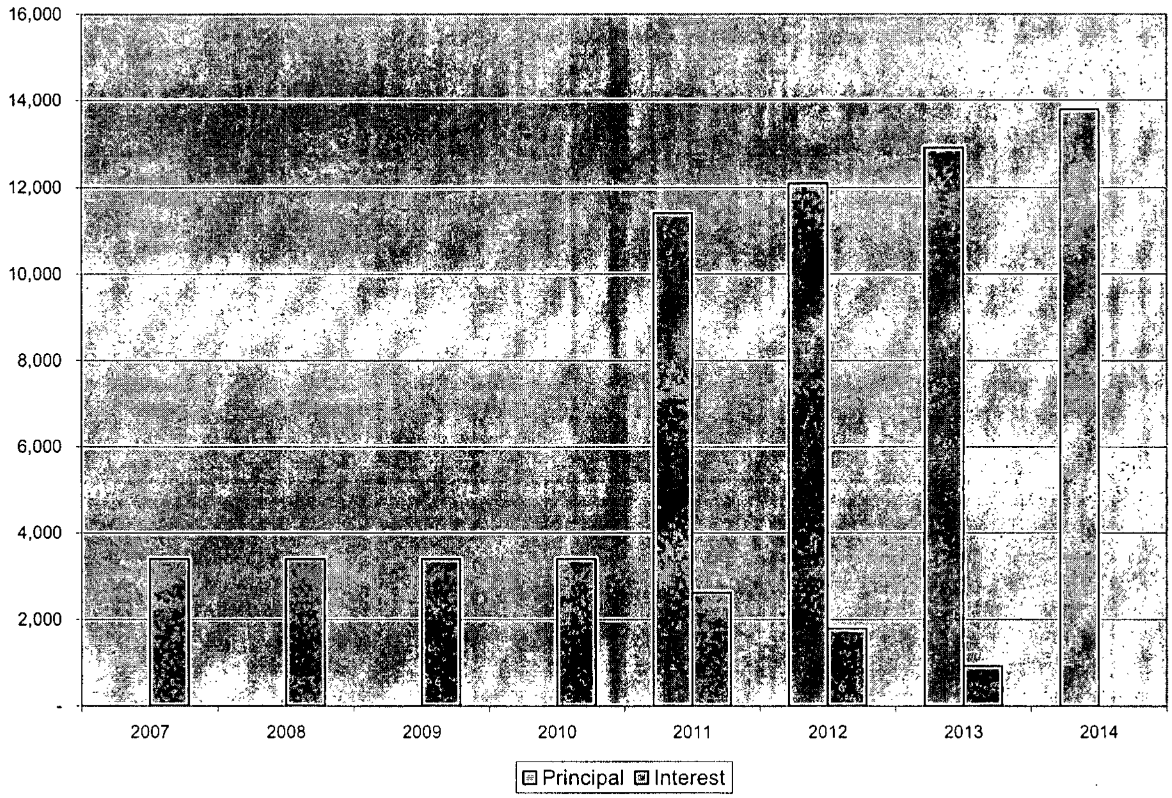
Fixed interest on the bonds is paid semi-annually on July 1 and January 1 of each year. Variable interest is paid weekly. There were no principal maturities for the year ended June 30, 2006. The bonds mature in the fiscal year ended June 30, 2021.

MEAD-ADELANTO PROJECT
Debt Service Requirements
Fiscal Year Ending June 30, 2006 ($ in thousands)



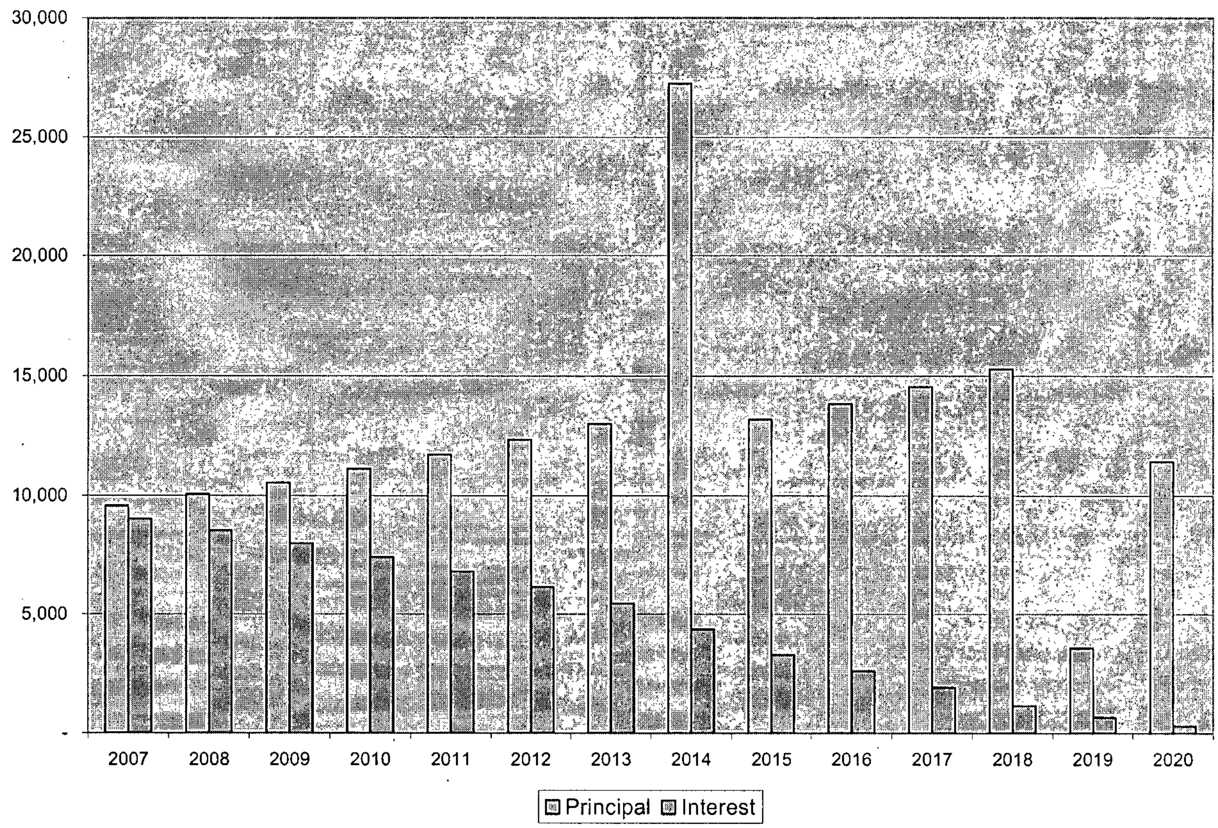
Fixed interest on the bonds is paid semi-annually on July 1 and January 1 of each year. Variable interest is paid Tuesdays, Wednesdays, and Thursdays of every week. There were no principal maturities for the year ended June 30, 2006. The bonds mature in the fiscal year ended June 30, 2021.

MULTIPLE PROJECT FUND
Debt Service Requirements
Fiscal Year Ending June 30, 2006 ($ in thousands)



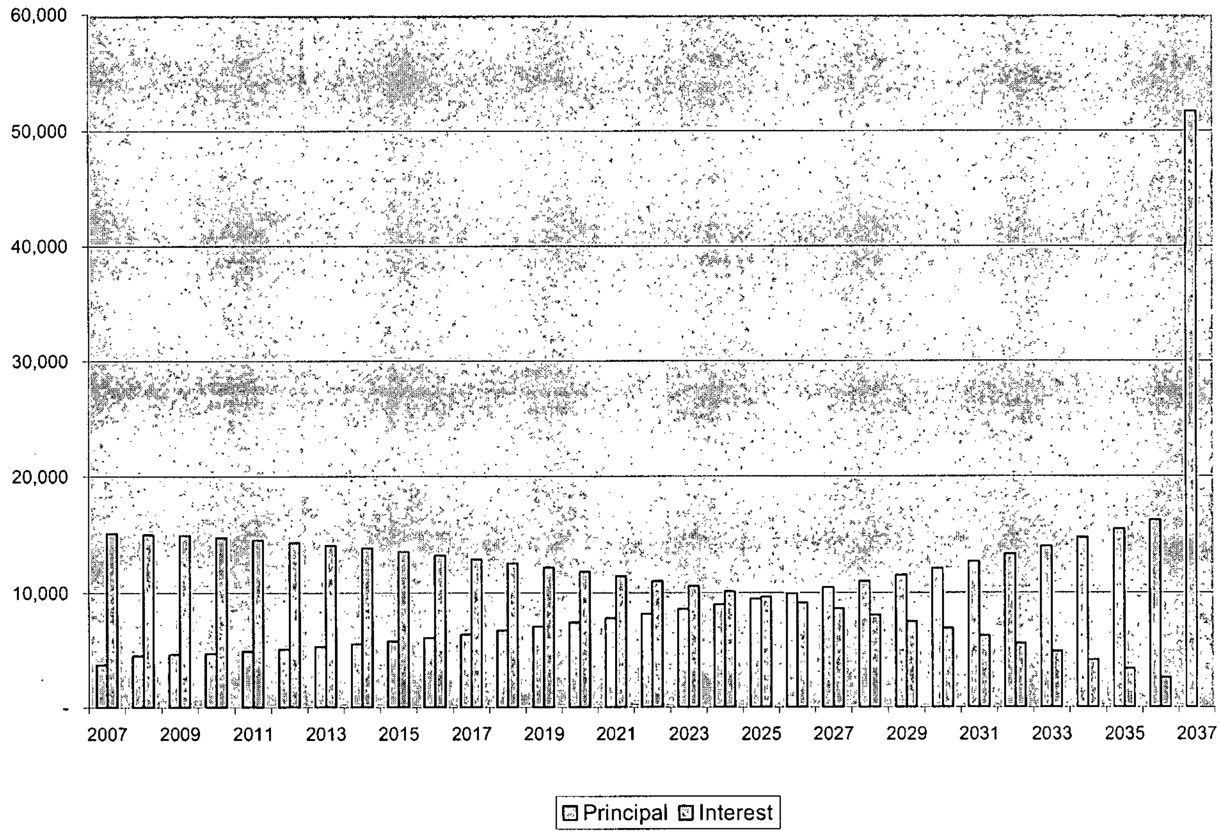
Interest payments on the bonds are payable semi-annually on July 1 and January 1 of each year. Par value of bonds that matured and were redeemed on July 1, 2005 was $170.2 million. A total of $50.2 million of the outstanding Multiple Project Revenue Bonds are not subject to redemption prior to maturity. The bonds mature in the fiscal year ended June 30, 2014.

SAN JUAN PROJECT
Debt Service Requirements
Fiscal Year Ending June 30, 2006 ($ in thousands)



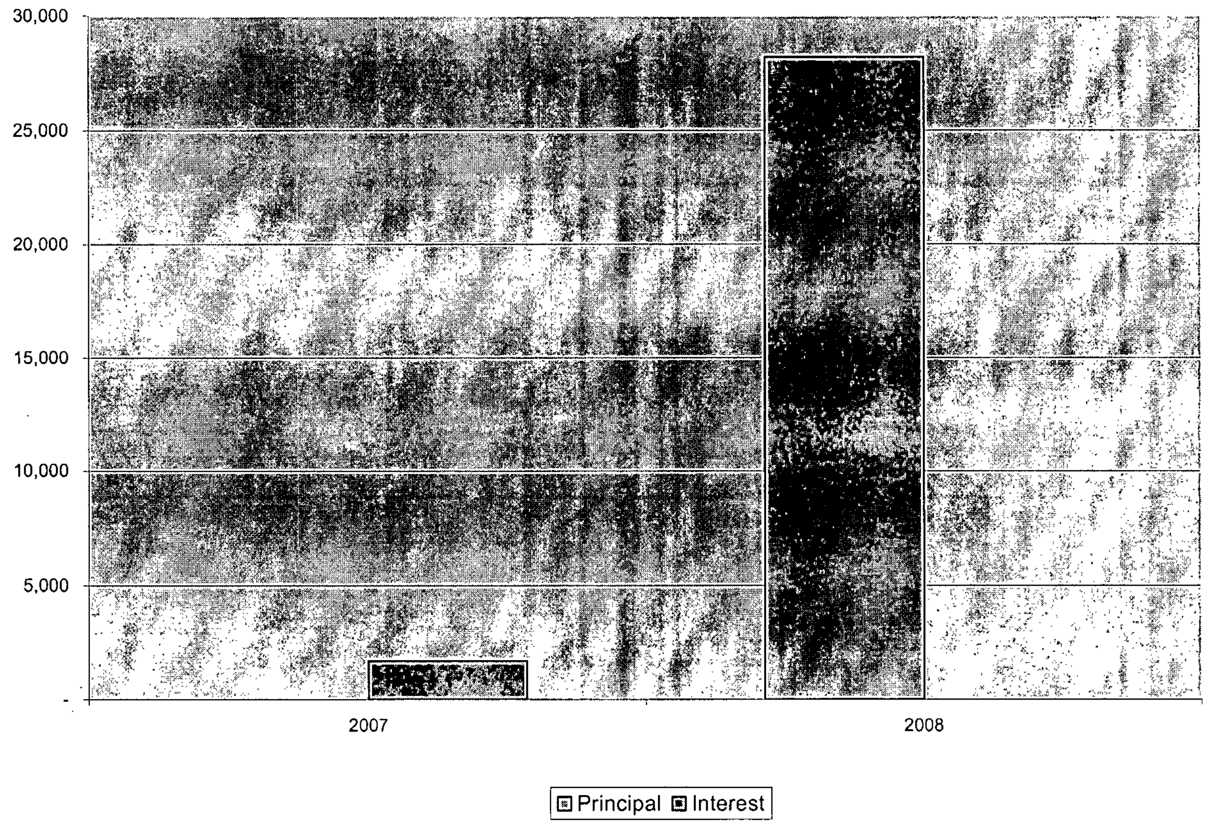
Interest payments on the bonds are payable semi-annually on July 1 and January 1 of each year. Principal maturities of $9.2 million were paid on January 1, 2006. The bonds mature in the fiscal year ended June 30, 2020.

MAGNOLIA POWER PROJECT
Debt Service Requirements
Fiscal Year Ending June 30, 2006 ($ in thousands)



Interest payments on the bonds are payable semi-annually on July 1 and January 1 of each year. There were no principal maturities for the year ended June 30, 2006. The bonds mature in the fiscal year ended June 30, 2037.

NATURAL GAS PROJECT
Debt Service Requirements
Fiscal Year Ending June 30, 2006 ($ in thousands)



Interest payments on the outstanding amount of the bonds is payable monthly. A portion of the principal totaling $1.7 million was paid on June 1, 2006. The bonds mature in the fiscal year ended June 30, 2008 unless the maturity is extended with the consent of the owners.

Financial Outlook - The Authority's credit strength is based on:

- The collective credit strengths of each project participant;
- The absence of concentration risk as evidenced by the lack of substantial reliance by one participant on the resources financed;
- The low cost power the Projects provide the participants; and,
- Strong legal provisions.

The Authority has take-or-pay power sales, natural gas sales and transmission service contracts which unconditionally require the Participants to pay for the cost of operating and maintaining the Projects, including debt service, whether or not the Projects are operating or operable. Although the contracts have not been court-tested, a municipal utility's authority to enter into such contracts is rooted in the State's constitutional provisions for municipal electric utilities.

Through the collaborative efforts of its members, the Authority has developed a comprehensive and dynamic strategic plan that provides a common vision for its members and a platform for joint action. SCPPA continues its involvement in legislative and regulatory affairs at both the state and federal levels to protect represented customers, by assuring resource adequacy, excellent reliability, and environmental stewardship. Backed by one of the strongest financial ratings in the utility industry, SCPPA maintains its traditional role of providing financing for its members' natural gas, generation and transmission projects. In addition to the conventional areas of power, investments are also being made to provide customers with more renewable generation and energy efficiency. Renewable energy will continue to play an important role for the future. Investment by SCPPA members in renewable programs, have totaled nearly $70 million over the past five years.

Natural Gas Reserve Acquisition Project - Several SCPPA members, the cities of Anaheim, Burbank, Colton, Glendale, and Pasadena, in addition to LADWP and Turlock Irrigation District, realized one of their goals in acquiring natural gas reserves for their own generating facilities.

On July 1, 2005, the acquisition of natural gas reserves and other real property from Anschutz Corporation in Pinedale, Wyoming was successfully completed. The transaction totaled in excess of $300 million. SCPPA financed approximately $26 million on behalf of Anaheim, Burbank, and Colton. Gas began to flow to the participants at 12:01 a.m. on July 1, 2005.

This is a unique project and is believed to be the largest natural gas field owned by public power utilities and should assure the participants a secure long-term and stable supply of natural gas to fuel the various power plants. All of the participants, as well as LADWP and the Turlock Irrigation District, have agreed to pool the operations under an agreement with SCPPA to assure close coordination and operation efficiencies.

Renewable Projects - SCPPA members are committed to the use of renewable energy resources in the future.

Energy from the High Winds Energy Center in Solano County, California, is now a part of the participating members' resource portfolios. SCPPA members, including the cities of Anaheim, Azusa, Colton, Glendale, and Pasadena, contracted with PPM Energy (a division of Pacificorp Holdings) for 30 megawatts (MW) of the 150 MW wind facility. PPM also provided a firming service, which guaranteed SCPPA members firm delivery of energy, at predetermined rates, regardless of the wind conditions at the site. Although the purchase contracts under the project were between the individual members and PPM, SCPPA played a key role in bringing this project to a reality through the issuance of the Renewable RFP and coordinating contract negotiations.

SCPPA has entered into a Power Purchase Agreement with Ameresco Chiquita Energy LLC for 100% of the electric generation from a landfill gas to energy facility to be located at the landfill site in Valencia, California (Ameresco Landfill Gas to Energy Project). The SCPPA participants in this project include the cities of Anaheim, Burbank, Glendale, and Pasadena, with their respective shares listed below. This project, which is expected to go on-line December 31, 2007, will initially be for 8 Megawatts with an option to increase the output by an additional 8 Megawatts in the future when additional gas becomes available.

Participants	Contract Share
City of Anaheim	33.3333%
City of Burbank	16.6667%
City of Glendale	33.3333%
City of Pasadena	16.6667%

Summary

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

MOSS-ADAMS LLP

CERTIFIED PUBLIC ACCOUNTANTS

INDEPENDENT AUDITOR'S REPORT

To the Board of Directors and Participants of
Southern California Public Power Authority

We have audited the accompanying combined statements of net assets (deficit) of Southern California Public Power Authority (the Authority) as of June 30, 2006 and 2005 and the related combined statements of revenues, expenses and changes in net assets (deficit) and cash flows for the years then ended. These financial statements are the responsibility of the Authority's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Southern California Public Power Authority as of June 30, 2006 and 2005 and the results of its operations and its cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

The management's discussion and analysis preceding the combined financial statements is not a required part of the basic financial statements but is supplementary information required by the Governmental Accounting Standards Board. We have applied certain limited procedures, which consisted principally of inquiries of management regarding the methods of measurement and presentation of the required supplementary information. However, we did not audit the information and express no opinion on it.

The additional supplemental information following the combined financial statements and notes to combined financial statements is also not a required part of the basic financial statements but is supplementary information provided for purposes of additional analysis. We did not audit or perform any other procedures on this information and express no opinion on it.

Moss Adams LLP

Vancouver, Washington
September 1, 2006

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINED STATEMENTS OF NET ASSETS (DEFICIT)
JUNE 30, 2006
(AMOUNTS IN THOUSANDS)

	Palo Verde Project	Southern Transmission System Project	Hoover Uprating Project	Mead- Phoenix Project	Mead- Adelanto Project	Multiple Project Fund
ASSETS						
Noncurrent assets						
Utility plant						
Production	$ 647,672	$ -	$ -	$ -	$ -	$ -
Transmission	14,076	674,606	-	50,770	172,319	-
General	2,770	18,911	21	2,640	473	-
Natural gas reserves	-	-	-	-	-	-
	664,518	693,517	21	53,410	172,792	-
Less - accumulated depreciation	560,670	390,618	21	14,834	46,260	-
	103,848	302,899	-	38,576	126,532	-
Construction work in progress	12,401	-	-	80	-	-
Nuclear fuel, at amortized cost	15,830	-	-	-	-	-
Net utility plant	132,079	302,899	-	38,656	126,532	-
Special funds						
Restricted investments						
Escrow accounts	-	6,535	-	-	-	-
Decommissioning funds	133,489	-	-	-	-	-
Other funds	23,629	64,669	2,813	11,394	33,939	65,395
Total restricted investments	157,118	71,204	2,813	11,394	33,939	65,395
Unrestricted investments						
Other funds	82,788	-	560	-	-	-
Total special funds	239,906	71,204	3,373	11,394	33,939	65,395
Other noncurrent assets						
Advance to IPA - restricted	-	11,550	-	-	-	-
Advances for capacity and energy, net - restricted	-	-	16,405	-	-	-
Deferred debit	-	-	-	-	-	-
Unamortized debt expenses	784	6,642	269	807	2,673	-
Other assets	-	-	-	-	-	-
Total other noncurrent assets	784	18,192	16,674	807	2,673	-
Total noncurrent assets	372,769	392,295	20,047	50,857	163,144	65,395
Current assets						
Special funds						
Cash and cash equivalents - restricted	1,824	15,497	18	1,883	3,567	-
Cash and cash equivalents - unrestricted	3,776	1,109	776	291	976	-
Interest receivable	1,414	28	29	300	848	2,130
Accounts receivable	6,934	1,090	-	-	-	-
Due from other project - restricted	-	-	-	5,013	13,787	-
Materials and supplies	6,711	-	-	-	-	-
Prepaid and other assets	37	-	-	-	-	-
Total current assets	20,696	17,724	823	7,487	19,178	2,130
Total assets	$ 393,465	$ 410,019	$ 20,870	$ 58,344	$ 182,322	$ 67,525
LIABILITIES						
Noncurrent liabilities						
Long-term debt	$ 98,215	$ 755,702	$ 16,821	$ 63,154	$ 202,596	$ 41,279
Notes payable	55,736	-	-	-	-	-
Advances from participants	-	-	-	-	-	-
Total noncurrent liabilities	153,951	755,702	16,821	63,154	202,596	41,279
Current liabilities						
Debt due within one year	11,545	34,230	1,315	3,250	10,850	-
Notes payable due within one year	4,526	-	-	-	-	-
Advances from participants due within one year	-	-	-	-	-	-
Accrued interest	360	9,402	233	960	2,824	1,694
Accounts payable and accruals	11,039	1,596	106	531	1,050	-
Accrued property tax	1,830	-	-	-	-	-
Due to other projects	-	-	-	-	-	18,800
Total current liabilities	29,300	45,228	1,654	4,741	14,724	20,494
Total liabilities	183,251	800,930	18,475	67,895	217,320	61,773
NET ASSETS (DEFICIT)						
Invested in capital assets, net of related debt and advances from participants	23,103	(480,390)	-	(26,941)	(84,242)	-
Restricted net assets (deficit)	99,600	88,876	1,163	17,630	49,317	5,752
Unrestricted net assets (deficit)	87,511	603	1,232	(240)	(73)	-
Total net assets (deficit)	210,214	(390,911)	2,395	(9,551)	(34,998)	5,752
Total liabilties and net assets (deficit)	$ 393,465	$ 410,019	$ 20,870	$ 58,344	$ 182,322	$ 67,525

See accompanying notes.

(AMOUNTS IN THOUSANDS)

San Juan Project	Magnolia Power Project	Natural Gas Project	Ormat Geothermal Project	Projects' Stabilization Fund	Total	Eliminations	Total Combined
$ 173,713	$ 277,109	$ 592	$ -	$ -	$ 1,099,086	$ -	$ 1,099,086
-	15,079	-	-	-	926,850	-	926,850
7,443	14,761	693	-	-	47,712	-	47,712
-	-	44,747	-	-	44,747	-	44,747
181,156	306,949	46,032	-	-	2,118,395	-	2,118,395
137,888	8,492	2,646	-	-	1,161,429	-	1,161,429
43,268	298,457	43,386	-	-	956,966	-	956,966
6,570	-	3,752	-	-	22,803	-	22,803
-	-	-	-	-	15,830	-	15,830
49,838	298,457	47,138	-	-	995,599	-	995,599
-	-	-	-	-	6,535	-	6,535
-	-	-	-	-	133,489	-	133,489
38,589	26,241	3,705	1,733	63,018	335,125	-	335,125
38,589	26,241	3,705	1,733	63,018	475,149	-	475,149
-	-	-	-	-	83,348	-	83,348
38,589	26,241	3,705	1,733	63,018	558,497	-	558,497
-	-	-	-	-	11,550	-	11,550
-	-	-	-	-	16,405	-	16,405
23,853	-	-	-	-	23,853	-	23,853
1,653	5,038	108	-	-	17,974	-	17,974
70	-	-	-	-	70	-	70
25,576	5,038	108	-	-	69,852	-	69,852
114,003	329,736	50,951	1,733	63,018	1,623,948	-	1,623,948
5,081	11,278	3,685	611	3,075	46,519	-	46,519
6,113	14,876	6,342	-	-	34,259	-	34,259
129	375	6	7	500	5,766	-	5,766
835	2,154	4,429	-	-	15,442	-	15,442
-	-	-	-	-	18,800	(18,800)	-
3,427	9,877	-	-	-	20,015	-	20,015
343	216	552	-	-	1,148	-	1,148
15,928	38,776	15,014	618	3,575	141,949	(18,800)	123,149
$ 129,931	$ 368,512	$ 65,965	$ 2,351	$ 66,593	$ 1,765,897	$ (18,800)	$ 1,747,097
$ 171,715	$ 316,740	$ 28,200	$ -	$ -	$ 1,694,422	$ -	$ 1,694,422
-	3,965	-	-	-	59,701	-	59,701
32,000	1,510	19,027	-	-	52,537	-	52,537
203,715	322,215	47,227	-	-	1,806,660	-	1,806,660
9,570	3,735	-	-	-	74,495	-	74,495
-	1,182	-	-	-	5,708	-	5,708
-	26,652	6,643	-	-	33,295	-	33,295
4,624	7,662	145	-	-	27,904	-	27,904
3,510	11,507	7,087	2,344	-	38,770	-	38,770
219	-	4,748	-	-	6,797	-	6,797
-	-	-	-	-	18,800	(18,800)	-
17,923	50,738	18,623	2,344	-	205,769	(18,800)	186,969
221,638	372,953	65,850	2,344	-	2,012,429	(18,800)	1,993,629
(129,794)	(15,332)	(1,608)	-	-	(715,204)	-	(715,204)
31,027	(996)	2,769	-	66,594	361,732	-	361,732
7,060	11,887	(1,046)	7	(1)	106,940	-	106,940
(91,707)	(4,441)	115	7	66,593	(246,532)	-	(246,532)
$ 129,931	$ 368,512	$ 65,965	$ 2,351	$ 66,593	$ 1,765,897	$ (18,800)	$ 1,747,097

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINED STATEMENTS OF NET ASSETS (DEFICIT)
JUNE 30, 2005
(AMOUNTS IN THOUSANDS)

	Palo Verde Project	Southern Transmission System Project	Hoover Uprating Project	Mead- Phoenix Project	Mead- Adelanto Project
ASSETS					
Noncurrent assets					
Utility plant					
Production	$ 636,588	$ -	$ -	$ -	$ -
Transmission	14,057	674,606	-	50,770	172,319
General	2,668	18,911	21	2,640	473
	653,313	693,517	21	53,410	172,792
Less - accumulated depreciation	539,190	370,989	21	13,431	41,760
	114,123	322,528	-	39,979	131,032
Construction work in progress	16,650	-	-	77	-
Nuclear fuel, at amortized cost	14,652	-	-	-	-
Net utility plant	145,425	322,528	-	40,056	131,032
Special funds					
Restricted investments					
Escrow accounts	-	10,545	-	-	-
Decommissioning funds	131,991	-	-	-	-
Other funds	32,038	42,591	2,654	8,765	24,130
Total restricted investments	164,029	53,136	2,654	8,765	24,130
Unrestricted investments					
Other funds	86,592	-	560	-	-
Total special funds	250,621	53,136	3,214	8,765	24,130
Other noncurrent assets					
Advance to IPA - restricted	-	11,550	-	-	-
Advances for capacity and energy, net - restricted	-	-	17,710	-	-
Deferred debit	-	-	-	-	-
Unamortized debt expenses	1,136	7,367	330	931	3,088
Total other noncurrent assets	1,136	18,917	18,040	931	3,088
Total noncurrent assets	397,182	394,581	21,254	49,752	158,250
Current assets					
Special funds					
Cash and cash equivalents - restricted	5,247	36,160	179	1,181	3,007
Cash and cash equivalents - unrestricted	1,832	652	829	262	724
Interest receivable	1,426	28	26	323	888
Accounts receivable	3,390	44	-	30	(7)
Due from other project - restricted	-	-	-	4,656	12,803
Materials and supplies	6,649	-	-	-	-
Total current assets	18,544	36,884	1,034	6,452	17,415
Total assets	$ 415,726	$ 431,465	$ 22,288	$ 56,204	$ 175,665
LIABILITIES					
Noncurrent liabilities					
Long-term debt	$ 107,707	$ 777,888	$ 17,716	$ 65,934	$ 212,155
Notes payable	59,869	-	-	-	-
Advances from participants due within one year	-	-	-	-	-
Total noncurrent liabilities	167,576	777,888	17,716	65,934	212,155
Current liabilities					
Debt due within one year	11,300	31,470	1,275	-	-
Notes payable due within one year	4,307	-	-	-	-
Accrued interest	1,419	8,214	244	1,013	2,946
Accounts payable and accruals	14,105	2,435	120	310	869
Accrued property tax	1,800	-	-	-	-
Due to other projects	-	-	-	-	-
Total current liabilities	32,931	42,119	1,639	1,323	3,815
Total liabilities	200,507	820,007	19,355	67,257	215,970
NET ASSETS (DEFICIT)					
Invested in capital assets, net of related debt and advances from participants	27,418	(479,463)	-	(24,946)	(78,036)
Restricted net assets (deficit)	100,084	92,660	1,660	13,911	37,882
Unrestricted net assets (deficit)	87,717	(1,739)	1,273	(18)	(151)
Total net assets (deficit)	215,219	(388,542)	2,933	(11,053)	(40,305)
Total liabilties and net assets (deficit)	$ 415,726	$ 431,465	$ 22,288	$ 56,204	$ 175,665

See accompanying notes.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINED STATEMENTS OF NET ASSETS (DEFICIT)
JUNE 30, 2005
(AMOUNTS IN THOUSANDS)

Multiple Project Fund	San Juan Project	Magnolia Power Project	Projects' Stabilization Fund	Total	Eliminations	Total Combined
$ -	$ 173,592	$ -	$ -	$ 810,180	$ -	$ 810,180
-	-	-	-	911,752	-	911,752
-	7,422	-	-	32,135	-	32,135
-	181,014	-	-	1,754,067	-	1,754,067
-	124,378	-	-	1,089,769	-	1,089,769
-	56,636	-	-	664,298	-	664,298
-	1,339	289,276	-	307,342	-	307,342
-	-	-	-	14,652	-	14,652
-	57,975	289,276	-	986,292	-	986,292
-	-	-	-	10,545	-	10,545
-	-	-	-	131,991	-	131,991
233,873	31,351	35,080	49,116	459,598	-	459,598
233,873	31,351	35,080	49,116	602,134	-	602,134
-	-	-	-	87,152	-	87,152
233,873	31,351	35,080	49,116	689,286	-	689,286
-	-	-	-	11,550	-	11,550
-	-	-	-	17,710	-	17,710
-	13,000	-	-	13,000	-	13,000
-	2,009	5,397	-	20,258	-	20,258
-	15,009	5,397	-	62,518	-	62,518
233,873	104,335	329,753	49,116	1,738,096	-	1,738,096
-	4,766	19,169	24,480	94,189	-	94,189
-	9,752	-	-	14,051	-	14,051
8,322	44	333	517	11,907	-	11,907
-	120	28	-	3,605	-	3,605
-	-	-	-	17,459	(17,459)	-
-	3,336	-	-	9,985	-	9,985
8,322	18,018	19,530	24,997	151,196	(17,459)	133,737
$ 242,195	$ 122,353	$ 349,283	$ 74,113	$ 1,889,292	$ (17,459)	$ 1,871,833
$ 202,104	$ 181,459	$ 320,909	$ -	$ 1,885,872	$ -	$ 1,885,872
-	-	-	-	59,869	-	59,869
-	16,000	-	-	16,000	-	16,000
202,104	197,459	320,909	-	1,961,741	-	1,961,741
8,100	9,160	-	-	61,305	-	61,305
-	-	-	-	4,307	-	4,307
6,932	3,632	7,585	-	31,985	-	31,985
-	4,834	20,789	-	43,462	-	43,462
-	264	-	-	2,064	-	2,064
17,459	-	-	-	17,459	(17,459)	-
32,491	17,890	28,374	-	160,582	(17,459)	143,123
234,595	215,349	349,283	-	2,122,323	(17,459)	2,104,864
-	(130,894)	28,013	-	(657,908)	-	(657,908)
7,600	32,529	(28,013)	74,113	332,426	-	332,426
-	5,369	-	-	92,451	-	92,451
7,600	(92,996)	-	74,113	(233,031)	-	(233,031)
$ 242,195	$ 122,353	$ 349,283	$ 74,113	$ 1,889,292	$ (17,459)	$ 1,871,833

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINED STATEMENTS OF REVENUES, EXPENSES AND CHANGES IN NET ASSETS (DEFICIT)
FOR THE YEAR ENDED JUNE 30, 2006
(AMOUNTS IN THOUSANDS)

	Palo Verde Project	Southern Transmission System Project	Hoover Uprating Project	Mead- Phoenix Project	Mead- Adelanto Project
Operating revenues					
Sales of electric energy	$ 68,739	$ -	$ 2,359	$ -	$ -
Sales of transmission services	-	84,061	-	7,017	20,722
Sales of natural gas	-	-	-	-	-
Total operating revenues	68,739	84,061	2,359	7,017	20,722
Operating expenses					
Operations and maintenance	33,714	17,300	2,575	1,119	1,417
Depreciation, depletion and amortization	18,274	19,629	-	1,403	4,500
Amortization of nuclear fuel	6,860	-	-	-	-
Decommissioning	10,156	-	-	-	-
Total operating expenses	69,004	36,929	2,575	2,522	5,917
Operating income (loss)	(265)	47,132	(216)	4,495	14,805
Non operating revenues (expenses)					
Investment income	2,533	4,802	97	742	2,082
Debt expense	(7,273)	(54,303)	(419)	(3,735)	(11,580)
Loss on extinguishment of debt	-	-	-	-	-
Net non operating revenues (expenses)	(4,740)	(49,501)	(322)	(2,993)	(9,498)
Change in net assets (deficit)	(5,005)	(2,369)	(538)	1,502	5,307
Net assets (deficit) - beginning of year	215,219	(388,542)	2,933	(11,053)	(40,305)
Net withdrawal by participants	-	-	-	-	-
Net assets (deficit) - end of year	$ 210,214	$ (390,911)	$ 2,395	$ (9,551)	$ (34,998)

See accompanying notes.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINED STATEMENTS OF REVENUES, EXPENSES AND CHANGES IN NET ASSETS (DEFICIT)
FOR THE YEAR ENDED JUNE 30, 2006
(AMOUNTS IN THOUSANDS)

Multiple Project Fund	San Juan Project	Magnolia Power Project	Natural Gas Project	Ormat Geothermal Project	Projects' Stabilization Fund	Total Combined
$ -	$ 69,123	$ 69,837	$ -	$ 886	$ -	$ 210,944
-	-	-	-	-	-	111,800
-	-	-	8,243	-	-	8,243
-	69,123	69,837	8,243	886	-	330,987
-	46,883	54,873	4,150	914	-	162,945
-	10,489	8,492	2,646	-	-	65,433
-	-	-	-	-	-	6,860
-	3,113	-	-	-	-	13,269
-	60,485	63,365	6,796	914	-	248,507
-	8,638	6,472	1,447	(28)	-	82,480
4,245	2,112	988	101	35	1,195	18,932
(6,093)	(9,461)	(11,901)	(1,433)	-	-	(106,198)
-	-	-	-	-	-	-
(1,848)	(7,349)	(10,913)	(1,332)	35	1,195	(87,266)
(1,848)	1,289	(4,441)	115	7	1,195	(4,786)
7,600	(92,996)	-	-	-	74,113	(233,031)
-	-	-	-	-	(8,715)	(8,715)
$ 5,752	$ (91,707)	$ (4,441)	$ 115	$ 7	$ 66,593	$ (246,532)

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINED STATEMENTS OF REVENUES, EXPENSES AND CHANGES IN NET ASSETS (DEFICIT)
FOR THE YEAR ENDED JUNE 30, 2005
(AMOUNTS IN THOUSANDS)

	Palo Verde Project	Southern Transmission System Project	Hoover Uprating Project	Mead- Phoenix Project	Mead- Adelanto Project
Operating revenues					
Sales of electric energy	$ 60,341	$ -	$ 2,344	$ -	$ -
Sales of transmission services	-	83,715	-	3,854	10,237
Total operating revenues	60,341	83,715	2,344	3,854	10,237
Operating expenses					
Operations and maintenance	29,229	18,553	2,461	1,127	1,713
Depreciation, depletion and amortization	18,086	19,629	-	1,403	4,500
Amortization of nuclear fuel	8,241	-	-	-	-
Decommissioning	10,900	-	-	-	-
Total operating expenses	66,456	38,182	2,461	2,530	6,213
Operating income (loss)	(6,115)	45,533	(117)	1,324	4,024
Non operating revenues (expenses)					
Investment income	10,511	3,732	119	663	1,814
Debt expense	(8,793)	(56,131)	(516)	(3,628)	(11,230)
Loss on extinguishment of debt	(85,827)	-	-	-	-
Net non operating revenues (expenses)	(84,109)	(52,399)	(397)	(2,965)	(9,416)
Change in net assets (deficit)	(90,224)	(6,866)	(514)	(1,641)	(5,392)
Net assets (deficit) - beginning of year	327,946	(381,676)	3,447	(9,412)	(34,913)
Release of over billings from prior years	(22,503)	-	-	-	-
Net contribution by participants	-	-	-	-	-
Net assets (deficit) - end of year	$ 215,219	$ (388,542)	$ 2,933	$ (11,053)	$ (40,305)

See accompanying notes.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINED STATEMENTS OF REVENUES, EXPENSES AND CHANGES IN NET ASSETS (DEFICIT)
FOR THE YEAR ENDED JUNE 30, 2005
(AMOUNTS IN THOUSANDS)

Multiple Project Fund	San Juan Project	Magnolia Power Project	Projects' Stabilization Fund	Total Combined
$ -	$ 60,322	$ -	$ -	$ 123,007
-	-	-	-	97,806
-	60,322	-	-	220,813
-	42,755	-	-	95,838
-	10,216	-	-	53,834
-	-	-	-	8,241
-	3,113	-	-	14,013
-	56,084	-	-	171,926
-	4,238	-	-	48,887
16,582	1,547	-	1,663	36,631
(16,089)	(9,696)	-	-	(106,083)
-	-	-	-	(85,827)
493	(8,149)	-	1,663	(155,279)
493	(3,911)	-	1,663	(106,392)
7,107	(89,085)	-	51,455	(125,131)
-	-	-	-	(22,503)
-	-	-	20,995	20,995
$ 7,600	$ (92,996)	$ -	$ 74,113	$ (233,031)

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINED STATEMENTS OF CASH FLOWS
FOR THE YEAR ENDED JUNE 30, 2006
(AMOUNTS IN THOUSANDS)

	Palo Verde Project	Southern Transmission System Project	Hoover Uprating Project	Mead- Phoenix Project	Mead- Adelanto Project
Cash flows from operating activities					
Receipts from participants	$ 49,275	$ 84,135	$ 2,351	$ 7,083	$ 20,666
Receipts from sale of oil and gas	-	-	-	-	-
Payments to operating managers	(30,082)	(18,371)	(271)	(1,046)	(1,508)
Other disbursements and receipts	7,633	-	-	-	-
Net cash flows from operating activities	26,826	65,764	2,080	6,037	19,158
Cash flows from noncapital financing activities					
Advances (withdrawals) by participants, net	-	-	-	-	-
Cash flows from capital financing activities					
Additions to plant, net	(20,809)	-	-	(3)	-
Debt interest payments	(5,133)	(41,230)	(954)	(3,436)	(10,653)
Proceeds from notes	-	-	-	-	-
Proceeds from sale of bonds	-	-	-	-	-
Transfer of funds from escrow	-	4,200	-	-	-
Principal payments on debt	(11,300)	(31,470)	(1,275)	-	-
Transfer of funds to escrow	-	-	-	-	-
Payment for bond issue costs	-	-	-	-	-
Net cash used for capital and related financing activities	(37,242)	(68,500)	(2,229)	(3,439)	(10,653)
Cash flows from investing activities					
Interest received on investments	1,604	3,239	118	683	1,884
Purchases of investments	(14,254)	(36,500)	(1,774)	(4,537)	(13,430)
Proceeds from sale/maturity of investments	21,587	15,791	1,591	1,987	3,853
Net cash provided by (used for) investing activities	8,937	(17,470)	(65)	(1,867)	(7,693)
Net increase (decrease) in cash and cash equivalents	(1,479)	(20,206)	(214)	731	812
Cash and cash equivalents, beginning of year	7,079	36,812	1,008	1,443	3,731
Cash and cash equivalents, end of year	$ 5,600	$ 16,606	$ 794	$ 2,174	$ 4,543
Reconciliation of operating income (loss) to net cash provided by operating activities					
Operating income (loss)	$ (265)	$ 47,132	$ (216)	$ 4,495	$ 14,805
Adjustments to reconcile operating income (loss) to net cash provided by operating activities					
Depreciation	18,274	19,629	-	1,403	4,500
Decommissioning	10,156	-	-	-	-
Advances for capacity and energy	-	-	2,310	-	-
Amortization of nuclear fuel	6,860	-	-	-	-
Changes in assets and liabilities					
Accounts receivable	(3,544)	(1,046)	-	30	(7)
Accounts payable and accruals	(4,695)	49	(14)	106	(145)
Other	40	-	-	3	5
Net cash provided by operating activities	$ 26,826	$ 65,764	$ 2,080	$ 6,037	$ 19,158
Cash and cash equivalents as stated in the Combined Statements of Net Assets (Deficit)					
Cash and cash equivalents - restricted	$ 1,824	$ 15,497	$ 18	$ 1,883	$ 3,567
Cash and cash equivalents - unrestricted	3,776	1,109	776	291	976
	$ 5,600	$ 16,606	$ 794	$ 2,174	$ 4,543

See accompanying notes.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINED STATEMENTS OF CASH FLOWS
FOR THE YEAR ENDED JUNE 30, 2006
(AMOUNTS IN THOUSANDS)

Multiple Project Fund	San Juan Project	Magnolia Power Project	Natural Gas Project	Ormat Geothermal Energy Project	Projects' Stabilization Fund	Total Combined
$ -	$ 70,039	$ 78,649	$ 14,228	$ 3,031	$ -	$ 329,457
-	-	-	16,620	-	-	16,620
-	(45,013)	(52,528)	(18,920)	(715)	-	(168,454)
-	-	4	4	-	-	7,641
-	25,026	26,125	11,932	2,316	-	185,264
-	-	6,512	43,860	-	(8,715)	41,657
-	(5,421)	(25,531)	(69,165)	-	-	(120,929)
(8,626)	(8,461)	(15,959)	(1,186)	-	-	(95,638)
-	-	6,109	-	-	-	6,109
-	-	-	29,900	-	-	29,900
-	-	-	-	-	-	4,200
(170,200)	(9,160)	(1,012)	(1,700)	-	-	(226,117)
(89)	-	-	-	-	-	(89)
-	(97)	-	(214)	-	-	(311)
(178,915)	(23,139)	(36,393)	(42,365)	-	-	(402,875)
10,437	1,868	1,471	297	28	1,825	23,454
(418)	(28,558)	(41,284)	(3,697)	(1,733)	(17,070)	(163,255)
168,896	21,479	50,554	-	-	2,555	288,293
178,915	(5,211)	10,741	(3,400)	(1,705)	(12,690)	148,492
-	(3,324)	6,985	10,027	611	(21,405)	(27,462)
-	14,518	19,169	-	-	24,480	108,240
$ -	$ 11,194	$ 26,154	$ 10,027	$ 611	$ 3,075	$ 80,778
$ -	$ 8,638	$ 6,472	$ 1,447	$ (28)	$ -	$ 82,480
-	10,489	8,492	2,646	-	-	65,433
-	3,113	-	-	-	-	13,269
-	-	-	-	-	-	2,310
-	-	-	-	-	-	6,860
-	(785)	(12,196)	(2,058)	-	-	(19,606)
-	3,745	23,298	9,992	2,344	-	34,680
-	(174)	59	(95)	-	-	(162)
$ -	$ 25,026	$ 26,125	$ 11,932	$ 2,316	$ -	$ 185,264
$ -	$ 5,081	$ 11,278	$ 3,685	$ 611	$ 3,075	$ 46,519
-	6,113	14,876	6,342	-	-	34,259
$ -	$ 11,194	$ 26,154	$ 10,027	$ 611	$ 3,075	$ 80,778

See accompanying notes.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINED STATEMENTS OF CASH FLOWS
FOR THE YEAR ENDED JUNE 30, 2005
(AMOUNTS IN THOUSANDS)

	Palo Verde Project	Southern Transmission System Project	Hoover Uprating Project	Mead- Phoenix Project	Mead- Adelanto Project
Cash flows from operating activities					
Receipts from participants	$ 49,438	$ 71,742	$ 2,401	$ 3,707	$ 10,649
Payments to operating managers	(29,415)	(14,761)	(226)	(1,304)	(1,881)
Other receipts	3,533	-	-	116	-
Net cash flows from operating activities	23,556	56,981	2,175	2,519	8,768
Cash flows from noncapital financing activities					
Advances (withdrawals) by participants, net	-	-	-	-	-
Cash flows from capital financing activities					
Additions to plant, net	(20,189)	-	-	(65)	-
Debt interest payments	(6,686)	(39,615)	(998)	(3,349)	(10,469)
Proceeds from sale of bonds	-	-	-	-	-
Payment for defeasance of revenue bonds	-	-	-	-	-
Principal payments on debt	(63,680)	(28,535)	(1,230)	-	-
Transfer of funds to escrow	(43,827)	-	-	-	-
Payment for bond issue costs	-	-	-	(49)	(128)
Net cash used for capital and related financing activities	(134,382)	(68,150)	(2,228)	(3,463)	(10,597)
Cash flows from investing activities					
Interest received on investments	1,648	3,157	95	666	1,804
Purchases of investments	(90,071)	(29,245)	(1,010)	(1,047)	(2,190)
Proceeds from sale/maturity of investments	45,873	33,035	735	1,000	1,970
Net cash provided by (used for) investing activities	(42,550)	6,947	(180)	619	1,584
Net increase (decrease) in cash and cash equivalents	(153,376)	(4,222)	(233)	(325)	(245)
Cash and cash equivalents, beginning of year	160,455	41,034	1,241	1,768	3,976
Cash and cash equivalents, end of year	$ 7,079	$ 36,812	$ 1,008	$ 1,443	$ 3,731
Reconciliation of operating income (loss) to net cash provided by operating activities					
Operating income (loss)	$ (6,115)	$ 45,533	$ (117)	$ 1,324	$ 4,024
Adjustments to reconcile operating income (loss) to net cash provided by operating activities					
Depreciation	18,086	19,629	-	1,403	4,500
Decommissioning	10,900	-	-	-	-
Advances for capacity and energy	-	-	2,220	-	-
Amortization of nuclear fuel	8,241	-	-	-	-
Changes in assets and liabilities					
Accounts receivable	(2,518)	3,763	-	(30)	7
Accounts payable and accruals	(5,153)	(11,950)	69	(181)	234
Other	115	6	3	3	3
Net cash provided by operating activities	$ 23,556	$ 56,981	$ 2,175	$ 2,519	$ 8,768
Cash and cash equivalents as stated in the Combined Statements of Net Assets (Deficit)					
Cash and cash equivalents - restricted	$ 5,247	$ 36,160	$ 179	$ 1,181	$ 3,007
Cash and cash equivalents - unrestricted	1,832	652	829	262	724
	$ 7,079	$ 36,812	$ 1,008	$ 1,443	$ 3,731

See accompanying notes.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINED STATEMENTS OF CASH FLOWS
FOR THE YEAR ENDED JUNE 30, 2005
(AMOUNTS IN THOUSANDS)

Multiple Project Fund	San Juan Project	Magnolia Power Project	Projects' Stabilization Fund	Total Combined
$ -	$ 67,626	$ -	$ -	$ 205,563
-	(41,240)	-	-	(88,827)
-	-	-	-	3,649
-	26,386	-	-	120,385
-	-	9,631	20,996	30,627
-	(1,394)	(78,397)	-	(100,045)
(14,130)	(10,189)	(15,170)	-	(100,606)
-	78,084	-	-	78,084
-	(78,454)	-	-	(78,454)
(7,600)	(8,805)	-	-	(109,850)
-	-	-	-	(43,827)
-	(924)	-	-	(1,101)
(21,730)	(21,682)	(93,567)	-	(355,799)
16,763	1,447	1,814	1,624	29,018
(1,340)	(27,790)	(929)	(5,500)	(159,122)
6,307	23,486	94,337	6,405	213,148
21,730	(2,857)	95,222	2,529	83,044
-	1,847	11,286	23,525	(121,743)
-	12,671	7,883	955	229,983
$ -	$ 14,518	$ 19,169	$ 24,480	$ 108,240
$ -	$ 4,238	$ -	$ -	$ 48,887
-	10,216	-	-	53,834
-	3,113	-	-	14,013
-	-	-	-	2,220
-	-	-	-	8,241
-	4,678	-	-	5,900
-	4,212	-	-	(12,769)
-	(71)	-	-	59
$ -	$ 26,386	$ -	$ -	$ 120,385
$ -	$ 4,766	$ 19,169	$ 24,480	$ 94,189
-	9,752	-	-	14,051
$ -	$ 14,518	$ 19,169	$ 24,480	$ 108,240

Note 1 - Organization and Purpose

The Southern California Public Power Authority (the "Authority"), a public entity organized under the laws of the State of California, was formed by a Joint Powers Agreement dated as of November 1, 1980 pursuant to the Joint Exercise of Powers Act of the State of California. The Authority's participants consist of eleven Southern California cities and one public district of the State of California. The Authority was formed for the purpose of planning, financing, developing, acquiring, constructing, operating and maintaining projects for the generation and transmission of electric energy and production of natural gas for sale to its participants. The Joint Powers Agreement has a term of fifty years.

The Authority has interests in the following projects:

Palo Verde Project - On August 14, 1981, the Authority purchased a 5.91% interest in the Palo Verde Nuclear Generating Station ("PVNGS"), a 3,810 megawatt nuclear-fueled generating station near Phoenix, Arizona, a 5.56% ownership interest in the Arizona Nuclear Power Project High Voltage Switchyard, and a 6.55% share of the right to use certain portions of the Arizona Nuclear Power Project Valley Transmission System (collectively, the "Palo Verde Project"). Units 1, 2 and 3 of the Palo Verde Project began commercial operations in January 1986, September 1986, and January 1988, respectively.

Southern Transmission System Project - On May 1, 1983, the Authority entered into an agreement with the Intermountain Power Agency ("IPA"), to defray all the costs of acquisition and construction of the Southern Transmission System Project ("STS"), which provides for the transmission of energy from the Intermountain Generating Station in Utah to Southern California. STS commenced commercial operations in July 1986. The Department of Water and Power of the City of Los Angeles ("LADWP"), a member of the Authority, serves as project manager and operating agent of the Intermountain Power Project ("IPP").

Hoover Uprating Project - As of March 1, 1986, the Authority and six participants entered into an agreement pursuant to which each participant assigned its entitlement to capacity and associated firm energy to the Authority in return for the Authority's agreement to make advance payments to the United States Bureau of Reclamation ("USBR") on behalf of such participants. The Authority has an 18.68% interest in the contingent capacity of the Hoover Uprating Project ("HU").

Note 1 - Organization and Purpose (Continued)

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

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

Multiple Project Fund - During fiscal year 1990, the Authority issued Multiple Project Revenue Bonds for net proceeds of approximately $600 million to provide funds to finance costs of construction and acquisition of ownership interests or capacity rights in one or more, then unspecified, projects for the generation or transmission of electric energy. Certain of these funds were used to finance the Authority's interests in Mead-Phoenix and Mead-Adelanto. On July 1, 2005, $162.1 million of the Multiple Project Revenue Bonds were redeemed.

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

Magnolia Power Project - In March 2003, the Authority received approval from the California Energy Commission for construction of the Magnolia Power Project. The Project consists of a combined cycle natural gas-fired generating plant with a nominally rated net base capacity of 242 megawatts and was built on a site in the City of Burbank, California. The plant is the first that is wholly owned by the Authority and entitlements to 100% of the capacity and energy of the Project have been sold to six of its members. The City of Burbank, a Project participant, managed its construction and also serves as the Operating Agent for the Project. Commercial operations began September 22, 2005.

NOTES TO COMBINED FINANCIAL STATEMENTS (In Thousands)

Note 1 - Organization and Purpose (Continued)

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

Ormat Geothermal Project - The Authority entered into long term Power Purchase Agreements in December 2005 with divisions of Ormat Technologies, Inc. for 20 megawatts ("MW") of electric generation from geothermal energy facilities located in Heber, California. The Project started delivery of 10 MW in January 2006 and is expected to receive additional deliveries in December 2007. The City of Anaheim acts as the Scheduling Coordinator on behalf of the Project Participants.

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

Participant Ownership Interests - The Authority's participants may elect to participate in the projects. As of June 30, 2006, the members have the following participation percentages in the Authority's operating projects:

Participants	Palo Verde	STS	Hoover Uprating	Mead-Phoenix	Mead-Adelanto	San Juan	Magnolia Power Project	Natural Gas Project	Ormat Geo-thermal Project
City of Los Angeles	67.0%	59.5%	-	24.8%	35.7%	-	-	-	-
City of Anaheim	-	17.6%	42.6%	24.2%	13.5%	-	38.0%	35.7%	60.0%
City of Riverside	5.4%	10.2%	31.9%	4.0%	13.5%	-	-	-	-
Imperial Irrigation District	6.5%	-	-	-	-	51.0%	-	-	-
City of Vernon	4.9%	-	-	-	-	-	-	-	-
City of Azusa	1.0%	-	4.2%	1.0%	2.2%	14.7%	-	-	-
City of Banning	1.0%	-	2.1%	1.0%	1.3%	9.8%	-	-	10.0%
City of Colton	1.0%	-	3.2%	1.0%	2.6%	14.7%	4.2%	7.1%	-
City of Burbank	4.4%	4.5%	16.0%	15.4%	11.5%	-	31.0%	14.3%	-
City of Glendale	4.4%	2.3%	-	14.8%	11.1%	9.8%	16.5%	28.6%	15.0%
City of Cerritos	-	-	-	-	-	-	4.2%	-	-
City of Pasadena	4.4%	5.9%	-	13.8%	8.6%	-	6.1%	14.3%	15.0%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Note 1 - Organization and Purpose (Continued)

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

The contracts expire as follows:

Palo Verde Project	2030
Southern Transmission System Project	2027
Hoover Uprating Project	2018
Mead-Phoenix Project	2030
Mead-Adelanto Project	2030
San Juan Project	2030
Magnolia Power Project	2036
Natural Gas Project	2030
Ormat Geothermal Project	2031

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

Note 2 - Summary of Significant Accounting Policies

Basis of Presentation - The combined financial statements of the Authority are prepared under the accrual basis of accounting in accordance with accounting principles generally accepted in the United States of America issued by the Governmental Accounting Standards Board (GASB) applicable to governmental entities that use proprietary fund accounting and the Financial Accounting Standards Board (FASB) issued prior to November 30, 1989 that do not conflict with rules issued by the GASB. Revenues are recognized when earned and expenses are recognized when incurred. The format of the Statement of Net Assets (Deficit) follows the inverted approach which is consistent with the Federal Energy Regulatory Commission (FERC).

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

- **Restricted** - This component consists of net assets on which constraints are placed as to their use. Constraints include those imposed by creditors (such as through debt covenants), contributors, or laws or regulation of other governments or constraints imposed by law through constitutional provisions or through enabling legislation.

- **Unrestricted** - This component of net assets consists of net assets that do not meet the definition of "restricted" or "invested in capital assets, net of related debt and advances from participants."

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

Note 2 - Summary of Significant Accounting Policies (Continued)

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

Depreciation expense is computed using the straight-line method based on the estimated service lives, principally thirty-five years for PVNGS, STS, Mead-Phoenix and Mead-Adelanto, thirty years for Magnolia and twenty-one years for SJGS.

Natural Gas Reserve Depletion - Depletion expense for the Natural Gas Project is computed using the unit of production method based on the future production of the proved developed producing wells, estimated at 30 years. For fiscal year 2006, the depletion rate was $2.13/MMbtu and the estimated total net revenue volume is 20,605,103 MMbtu to the period ending 2034.

Note 2 - Summary of Significant Accounting Policies (Continued)

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

	Balance July 1, 2005	Additions	Disposals	Transfers	Balance June 30, 2006
Nondepreciable utility plant					
Land	$ 42,472	$ -	$ -	$ -	$ 42,472
Construction work in progress	307,342	37,191	-	(325,482)	19,051
Contruction work in progress - gas	-	3,752	-	-	3,752
Nuclear fuel*	14,652	6,330	(5,152)	-	15,830
Total nondepreciable utility plant	364,466	47,273	(5,152)	(325,482)	81,105
Depreciable utility plant					
Production					
Nuclear generation (Palo Verde Project)	635,852	18,160	(7,076)	-	646,936
Coal-fired plant (San Juan Unit 3 Project)	173,591	213	(92)	-	173,712
Gas-fired plant (Magnolia Power Project)	-	-	-	277,109	277,109
Transmission	870,017	18	-	15,080	885,115
General	32,135	141	(18)	14,761	47,019
Acquisition of gas reserves	-	44,747	-	-	44,747
Intagibles	-	592	-	-	592
Well equipment and production facilities	-	693	-	-	693
Total depreciable utility plant	1,711,595	64,564	(7,186)	306,950	2,075,923
Less accumulated depreciation	(1,089,769)	(78,702)	7,042	-	(1,161,429)
Total utility plant, net	$ 986,292	$ 33,135	$ (5,296)	$ (18,532)	$ 995,599

Nuclear fuel disposals represent amortization.

Interest expense capitalized to construction work in progress net of capitalized interest income for the Magnolia Power Project was $3,064 and $13,467 for the years ended June 30, 2006 and 2005, respectively.

Nuclear Fuel - Nuclear fuel is amortized and charged to expense on the basis of actual thermal energy produced relative to total thermal energy expected to be produced over the life of the fuel. Under the provisions of the Nuclear Waste Policy Act of 1982, the federal government assesses each entity with nuclear operations, including the participants in PVNGS, $1 per megawatt hour of nuclear generation. The Authority records this charge as a current year expense. See Note 8 for information about spent nuclear fuel disposal.

Note 2 - Summary of Significant Accounting Policies (Continued)

Nuclear Decommissioning - Decommissioning of PVNGS is expected to commence subsequent to the year 2026. The total cost to decommission the Authority's interest in PVNGS is estimated to be $125.6 million in 2005 dollars ($339.5 million in 2022 dollars, assuming a 6% estimated annual inflation rate). This estimate is based on an updated site specific study prepared by an independent consultant in 2004. The Authority is providing for its share of the estimated future decommissioning costs over the remaining life of the nuclear power plant through annual charges to expense, which amounted to $10.2 million and $10.9 million in fiscal years 2006 and 2005, respectively. The decommissioning liability is included as a component of accumulated depreciation and was $202.7 and $192.6 million at June 30, 2006 and 2005, respectively.

The Authority contributes to external trusts set up in accordance with the Arizona Nuclear Power Plant participation agreement and Nuclear Regulatory Commission requirements. As of June 30, 2006, decommissioning funds totaled approximately $134.6 million, including approximately $1.1 million of interest receivable.

Demolition and Site Reclamation - Demolition and site reclamation of SJGS, which involves restoring the site to a "green" condition, is projected to commence subsequent to the year 2014. Based upon the study performed by an independent engineering firm, the Authority's share of the estimated demolition and site reclamation costs is $30.8 million in 2003 dollars. The Authority is providing for its share of the estimated future demolition costs over the remaining life of the power plant through annual charges to expense of $3.1 million. The demolition liability is included as a component of accumulated depreciation and totaled $40.5 million and $37.3 million at June 30, 2006 and 2005, respectively.

As of June 30, 2006, the Authority has not billed participants for the cost of demolition nor has it established a demolition fund.

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

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

Note 2 - Summary of Significant Accounting Policies (Continued)

Advances for Capacity and Energy - Advance payments to the United States Bureau of Reclamation for the uprating of the 17 generators at the Hoover Power Plant are included in advances for capacity and energy. These advances are being reduced by the principal portion of the credits on billings to the Authority for energy and capacity.

Advance to IPA - Advance to IPA consists of cash transferred to IPA for reserve and contingency and self insurance funding.

Unamortized Debt Expenses - Debt premiums, discounts, and issue expenses are deferred and amortized to expense over the lives of the related debt issues. Losses on refunding related to bonds redeemed by refunding bonds are amortized over the shorter of the life of the refunding bonds, or the remaining term of bonds refunded. Losses on early extinguishment of debt are recognized immediately. Unamortized issue costs are recorded as a non current asset. All other unamortized debt expenses are recorded as an offset or addition to long-term debt.

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

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

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

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

The recorded liability of the Multiple Project Fund of $18.8 million ($5.0 million payable to the Mead-Phoenix Project and $13.8 million payable to the Mead-Adelanto Project) is a result of the cumulative savings from the 1994 refunding of the 1989 Multiple Project Bonds. The partial refunding within five years of the original issuance triggered a recalculation of the arbitrage yield, reducing the Multiple Project Fund's rebate liability.

Note 2 - Summary of Significant Accounting Policies (Continued)

Arbitrage Rebate and Yield Restrictions (Continued)

During the fiscal year ended June 30, 2006, the Authority made rebate payments to the IRS of $1.47 million for the STS bonds and $0.87 million for Palo Verde bonds.

Recorded arbitrage rebate and yield restriction liabilities as of June 30, 2006, were $0.038 million for Palo Verde, $0.3 million for STS, $0.3 million for Mead-Phoenix, and $0.8 million for Mead-Adelanto.

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

In September 1998, the Palo Verde participants approved a resolution authorizing the Authority to bill the participants an additional $65 million annually through June 30, 2004 to pay for increased debt service costs as a result of a refunding completed in October 1997. In addition, the participants resolved to transfer any over billings, renewal and replacement excess funds or surplus amounts through June 30, 2004 into the Palo Verde reserve account. On November 20, 2003, the Authority adopted a resolution to utilize the amounts on deposit in the reserve accounts to pay a portion of the operating and maintenance expenses of the Palo Verde Project starting July 1, 2004. Funds held in the reserve account as a result of this resolution totaled $64.5 million and $68.8 million as of June 30, 2006 and 2005, respectively.

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

In kind contributions are valued at fair market value and recorded as participant revenue and fuel expense to the Magnolia Power Project. SCPPA values the participants' fuel contribution using monthly average pricing from the Project's OEMI fuel purchases. During the fiscal year ended June 30, 2006 the participants' contribution in kind was approximately 2.8 million MMBtu and was valued at approximately $25.0 million.

Reclassification - Certain 2005 balances have been reclassified to conform to 2006 presentation.

Note 3 - Investments

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

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

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

The operative Indentures of Trust in which securities are authorized for investment purposes relate to the Palo Verde Project Bonds, the Southern Transmission System Project Bonds, the Hoover Uprating Project Bonds, the Mead-Phoenix Project Bonds, the Mead-Adelanto Project Bonds, the Multiple Project Fund Bonds, the San Juan Project Bonds, the Magnolia Power Project Bonds, and the Natural Gas Project Bonds. Authorized investments for the Projects' Stabilization Fund are set forth in a resolution approved by the Board in 1996.

Eligible securities include:

- United States Treasury Securities, which are bonds or other obligations secured by the full faith and credit of the United States of America;
- Federal Agency Obligations, which have the full financial backing of the U.S. Government;
- Government Sponsored Enterprise Obligations, which are created by acts of Congress to provide liquidity for selected lending programs targeted by Congress;
- Repurchase Agreements, which are collateralized loan contracts where the seller includes a written agreement to repurchase the securities at a later date for a specified amount;
- Negotiable Certificates of Deposit, which are deposit liabilities issued by a nationally or state-chartered bank, a savings or a federal association or by a state-licensed branch of a foreign bank which has a short-term ratings of at least "A-1" by S&P and at least "P-1" by Moody's;
- Banker's Acceptances, a short term draft or bill of exchange guaranteed for payment at face value to the holder of the instrument on its maturity date, which has a short-term rating of at least "A-1" by S&P and at least "P-1" by Moody's;

NOTES TO COMBINED FINANCIAL STATEMENTS (In Thousands)

Note 3 – Investments (Continued)

- Commercial Paper, a short-term unsecured promissory note issued by non-financial or financial firms with a rating of at least "A-1" by S&P and at least "P-1" by Moody's;
- Medium Term Notes rated "A" or better and only those issued by corporations organized and operating within the United States, or by depository institutions licensed by the United States or any state and operating within the United States;
- Equity-Linked Notes, which are categorized as medium-term corporate notes and are subject to the constraints set forth in the Government code and the Authority's Investment Policy.

Investments at June 30, 2006 and 2005 are as follows:

June 30, 2006

	Palo Verde Project	Southern Trans- mission System Project	Hoover Uprating Project	Mead-Phoenix Project	Mead-Adelanto Project	Multiple Project Fund	San Juan Project	Magnolia Power Project	Natural Gas Project	Ormat Geothermal Project	Projects' Stabilization Fund	Total
U.S. Agencies	$ 167,590	$ 995	$ 2,152	$ -	$ -	$ -	$ 14,641	$ 19,423	$ -	$ 1,780	$ 63,018	$ 269,599
Agency Discount Notes	6,580	40,326	1,964	5,162	14,647	-	12,047	29,877	10,721	-	1,088	122,412
Treasury Coupon	477	-	-	-	-	7,435	-	-	-	-	-	7,912
Guaranteed investment contracts	64,584	37,180	-	8,095	22,990	57,960	21,323	-	-	-	-	212,132
Negotiable CD's	-	-	-	-	-	-	-	-	60	-	-	60
Commercial Paper	-	-	-	-	-	-	-	-	-	-	-	-
Equity Link Notes	4,452	-	-	-	-	-	-	-	-	-	-	4,452
Money Market Funds	1,823	9,309	51	311	845	-	1,772	3,095	2,951	564	1,987	22,708
Total	$ 245,506	$ 87,810	$ 4,167	$ 13,568	$ 38,482	$ 65,395	$ 49,783	$ 52,395	$ 13,732	$ 2,344	$ 66,093	$ 639,275
Restricted investments	$ 157,118	$ 71,204	$ 2,813	$ 11,394	$ 33,939	$ 65,395	$ 38,589	$ 26,241	$ 3,705	$ 1,733	$ 63,018	$ 475,149
Unrestricted investments	82,788	-	560	-	-	-	-	-	-	-	-	83,348
Cash and cash equivalents	5,600	16,606	794	2,174	4,543	-	11,194	26,154	10,027	611	3,075	80,778
Total	$ 245,506	$ 87,810	$ 4,167	$ 13,568	$ 38,482	$ 65,395	$ 49,783	$ 52,395	$ 13,732	$ 2,344	$ 66,093	$ 639,275

June 30, 2005

	Palo Verde Project	Southern Transmission System Project	Hoover Uprating Project	Mead-Phoenix Project	Mead-Adelanto Project	Multiple Project Fund	San Juan Project	Magnolia Power Project	Natural Gas Project	Ormat	Projects' Stabilization Fund	Total
Federal agencies	$ 183,212	$ 41,468	$ 4,025	$ 996	$ 3,374	$ -	$ 23,679	$ 50,315	$ -	$ -	$ 53,225	$ 360,294
US Government securities	-	10,544	-	-	-	7,435	-	-	-	-	-	17,979
Guaranteed investment contracts	68,890	36,507	-	8,765	24,130	226,438	21,323	3,696	-	-	-	389,749
Money market investment accounts	1,058	1,391	181	435	346	-	845	224	-	-	58	4,538
Medium term ntes	4,452	-	-	-	-	-	-	-	-	-	-	4,452
Cash	88	38	16	12	11	-	22	14	-	-	20,313	20,514
Total	$ 257,700	$ 89,948	$ 4,222	$ 10,208	$ 27,861	$ 233,873	$ 45,869	$ 54,249	$ -	$ -	$ 73,596	$ 797,526
Restricted investments	$ 164,029	$ 53,136	$ 2,654	$ 8,765	$ 24,130	$ 233,873	$ 31,351	$ 35,080	$ -	$ -	$ 49,116	$ 602,134
Unrestricted investments	86,592	-	560	-	-	-	-	-	-	-	-	87,152
Cash and cash equivalents	7,079	36,812	1,008	1,443	3,731	-	14,518	19,169	-	-	24,480	108,240
Total	$ 257,700	$ 89,948	$ 4,222	$ 10,208	$ 27,861	$ 233,873	$ 45,869	$ 54,249	$ -	$ -	$ 73,596	$ 797,526

Note 3 – Investments (Continued)

Interest Rate Risk
The Authority's investment policy limits the maturity of its investments to a maximum of 5 years for investments in the United States Treasury, Federal Agency, and Government Sponsored Enterprise securities, excluding: investments held in Project Debt Service Reserve; long-term commitments or agreements approved by the Authority's Board; 5 years for medium term corporate notes; 270 days for commercial paper; 180 days for banker's acceptances; and one year for negotiable certificates of deposits.

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

The Authority's investment policy specifies that all project funds may be invested in shares of beneficial interest for temporary periods, pending disbursement or reinvestment as allowed under the state of California Government Code ("Code"). The Code requires that the fund must have either 1) attained the highest ranking or highest letter and numerical rating provided by not less than two nationally recognized statistical rating organizations ("NRSRO") or 2) retained an investment advisor registered or exempt from registration with the Securities and Exchange Commission with not less than five years experience managing money market mutual funds with assets under management in excess of five hundred million dollars. As of June 30, 2006 and June 30, 2005, each of the money market funds in the portfolio have attained the highest possible ratings by three NRSRO's, specifically AAAm by Standard and Poor's, Aaa by Moody's Investors Service, and AAA by Fitch Ratings.

The U.S. government agency securities in the portfolio consist of securities issued by government-sponsored enterprises, which are not explicitly guaranteed by the U.S. government. As of June 30, 2006 and June 30, 2005, the U.S. government agency securities in the portfolio carried the highest possible credit ratings by the NRSRO's that rated them.

The Equity Link Notes (Medium Term Notes) in the portfolio consists of securities issued by corporations and carry a rating of AA by Standard and Poor's, Aa by Moody's Investor Service and AA by Fitch Rating.

Note 3 – Investments (Continued)

The Guaranteed Investment Contracts in the portfolio with AIG consist of securities issued by corporations and carry a rating of AA by Standard and Poor's, Aa by Moody's Investor Service and AA by Fitch Rating. The Guaranteed Investment Contracts in the portfolio with PNC carry a rating of A by Standard and Poor's, Aaa by Moody's Investor Service, and A by Fitch Rating.

The Investment Agreement Contract in the portfolio with FSA consists of securities issued by corporations and carries a rating of AAA by Standard and Poor's, Aaa by Moody's Investor Service, and AAA by Fitch Rating.

Concentration of Credit Risk

The Authority's investment policy specifies a 50% to 100% limitation on the amount that can be invested in U.S. government agency securities, except in certain issues of other Authority projects, such as the Southern Transmission System 1991 Series and the Mead-Adelanto and Mead-Phoenix projects.

Of the Authority's total investments as of June 30, 2006, $203,651,400 (33%), was invested in securities issued by the Federal Home Loan Bank; $87,416,445 (13%) was invested in securities issued by the Federal National Mortgage Association; $67,905,700 (11%) was invested in securities issued by the Federal Home Loan Mortgage Corporation; $64,583,699 (10%) was invested in an investment agreement with Financial Security Assurance (FSA); $89,045,847 (14%) was invested in a Guaranteed Investment Contract (GIC) with PNC Financial Securities Group; and $62,953,499 (10%) was invested in a GIC with American International Group (AIG).

Of the Authority's total investments as of June 30, 2005, $224,678,700 (29%), was invested in securities issued by the Federal Home Loan Bank; $55,653,843 (7%) was invested in securities issued by the Federal National Mortgage Association; $62,097,939 (8%) was invested in securities issued by the Federal Home Loan Mortgage Corporation; $68,890,578 (9%) was invested in an investment agreement with FSA; $259,333,654 (34%) was invested in a GIC with PNC Financial Securities Group; and $65,977,462 (9%) was invested in a GIC with AIG.

Note 4 - Derivative Instruments

Objective of the swaps - In order to protect against the potential of rising interest rates, the Authority has entered into six separate pay-fixed, receive-variable interest rate swaps and one fixed spread basis swap at a cost that is expected to be less over the life of the transaction than what the Authority would have paid to issue fixed-rate debt.

NOTES TO COMBINED FINANCIAL STATEMENTS (In Thousands)

Note 4 - Derivative Instruments (Continued)

Terms, fair values, and credit risk - The terms, including the fair values and credit ratings of the counterparties under the outstanding swaps as of June 30, 2006, are included below. In most cases, the notional amount of any swap matches the principal amount of the associated debt. Except as discussed under the rollover risk, the Authority's swap agreements contain scheduled reductions to outstanding notional amounts that are expected to approximately follow scheduled or anticipated reductions in the associated "bonds payable" category.

	Notional Amount	Effective Date	Fixed Rate Paid	Variable Rate Received	Fair Values	Swap Termination Date	Counterparty Credit Rating
MP 2004 Revenue Series A Bonds	$ 28,700	5/27/2004	3.894%	65% of LIBOR	$ (501)	7/1/2020	AA+/Aa2/AA+
MA 2004 Revenue Series A Bonds	96,025	5/27/2004	3.890%	65% of LIBOR	(1,641)	7/1/2020	AA+/Aa2/AA+
STS 2004 Fixed Rate Basis Swap	100,000	12/1/2004	BMA	65% of LIBOR plus 0.664%	748	7/1/2023	AA-/Aa2/A+
STS 2003 Subordinate Refunding Series A Bonds	50,950	4/24/2003	3.266%	65% of LIBOR	2,180	7/1/2022	AA-/Aa1/AA+
STS 2001 Subordinate Refunding Series A Bonds	79,795	6/14/2001	4.240%	BMA less 40 basis points	(6,312)	7/1/2021	AA+/Aa2/AA+
STS Swaption/Swap	125,000	2/6/2001	4.250%	60% of LIBOR	(12,437)	7/1/2022	AA-/Aa1/AA+
STS 1991 Revenue Bonds Series A	281,500	4/17/1991	6.380%	Bond variable coupon rate	(50,994)	6/30/2019	AA+/Aa2/-
	$ 761,970				$ (68,957)		

- **STS 2004 Swap** - In November 2004, the Authority entered into a floating-to-floating Fixed-Spread basis swap. Under the swap agreement, the Authority will pay a variable rate equal to the BMA index, and in exchange will receive 65% of LIBOR plus a fixed margin or spread of 66.4 basis points. The basis swap is expected to produce net positive cash flow for the Authority given the historical positive difference between the floating rate received and the floating rate paid. The fixed margin of 66.4 basis points represents the fair market or breakeven spread differential prevailing at the time the trade was executed. The swap expires on July 1, 2023.

- **MP 2004 Swap** - In connection with the issuance of the 2004 Mead-Phoenix Project Revenue Bonds Series A auction-rate security in May 2004, the Authority entered into an interest rate swap on March 3, 2004. The floating-to-fixed rate swap created synthetic fixed-rate debt for the Authority. Under the Swap Agreement, the Authority pays the counterparty a fixed rate of 3.894% and in exchange the Authority receives a floating rate index equal to 65% of one-month LIBOR. The swap agreement expires July 1, 2020. The Authority received approximately $1.8 million in an upfront payment in connection with the execution of the swap, which has been deferred and is being amortized as an interest yield adjustment over the life of the option. Approximately $13.5 million in Mead-Phoenix 2004 Project Revenue Bonds Series A are not swapped and remain floating-rate bonds. The floating rate on the related bonds as of June 30, 2006 was 3.80%.

Note 4 - Derivative Instruments (Continued)

- **MA 2004 Swap** - In connection with the issuance of the 2004 Mead-Adelanto Revenue Bonds Series A auction-rate security in May 2004, the Authority entered into an interest rate swap on March 3, 2004. The floating-to-fixed rate swap created synthetic fixed-rate debt for the Authority. Under the Swap Agreement, the Authority pays the counterparty a fixed rate of 3.89% for the swap and in exchange the Authority receives a floating rate index equal to 65% of one-month LIBOR. The swap agreement expires July 1, 2020. The Authority received approximately $5.9 million in an upfront payment in connection with the execution of the swap, which has been deferred and is being amortized as an interest yield adjustment over the life of the swap. Approximately $45.1 million in Mead-Adelanto 2004 Project Revenue Bonds Series A are not swapped and remain floating-rate bonds. The average floating rate on the related bonds as of June 30, 2006 was 3.80%.

- **STS 2003 Swap** - In April 2003, the Authority entered into an Interest Rate Swap agreement with a third party for the purpose of hedging against interest rate variations arising from the issuance of the 2003 Subordinate Refunding Series A Southern Transmission Project Revenue Bonds. The notional amount of the Swap Agreement is equal to the par value of the bonds. The Swap Agreement provides for the Authority to make payments to the counterparty on a fixed rate basis of 3.266%, and for the counterparty to make reciprocal payments based on a floating rate of 65% of one-month LIBOR. The floating rate on the related bonds at June 30, 2006 and 2005 was 3.70% and 2.00%, respectively. The agreement expires on July 1, 2022.

- **STS Swaption/Swap** - In February 2001, the Authority entered into a transaction whereby it sold an option (the "Swaption") on a floating-to-fixed interest rate swap. The Swaption was exercised on April 1, 2002. The floating rate on the swap paid by the counterparty is 60% of one-month LIBOR; the annual fixed rate on the swap paid by the Authority is 4.25%. In exchange for the right to exercise the Swaption, the counterparty paid the Authority a one-time up front option premium amount of $7.9 million which has been deferred and is being amortized as an interest yield adjustment over the life of the option. The swap expires on July 1, 2022.

Note 4 - Derivative Instruments (Continued)

- **STS 2001 Swap** - In June 2001, the Authority entered into an interest rate swap agreement with a counterparty for the purpose of hedging against interest rate variations arising from the issuance of the 2001 Subordinate Refunding Series A Southern Transmission Project Revenue Bonds. The notional amount of the Swap Agreement is equal to the par value of the bonds. The Swap Agreement provides for the Authority to make payments to the counterparty at a fixed rate of 4.24%, and for the counterparty to make reciprocal payments based on a variable rate. The reset dates of the variable rate occur weekly and the rate for a reset date will be the rate determined by the Bond Market Association Municipal Swap Index ("BMA") minus 40 basis points. The counterparty has the option to cancel the agreement on July 5, 2006 and on every Fixed Rate Payer Payment Date, thereafter, should the BMA index average more than 7% over a consecutive 180-day period. The floating rates on the bonds were 3.92% and 2.20% at June 30, 2006 and 2005, respectively. The swap expires on July 1, 2021.

- **STS 1991 Swap** - In fiscal year 1991, the Authority entered into an interest rate swap Agreement with a counterparty for the purpose of hedging against interest rate fluctuations arising from the issuance of the 1991 Subordinate Refunding Series Southern Transmission Project Revenue Bonds. The notional amount of the Swap Agreement is equal to the par value of the bonds. Under the Swap Agreement, the Authority pays the counterparty a fixed rate of 6.38%; in exchange, the Authority receives payments mirroring the bond variable coupon rate (3.87% and 2.21% at June 30, 2006 and 2005, respectively). The swap expires on June 30, 2019.

Fair value – Except for the STS 2004 and the STS 2003 swaps, all swaps had a negative fair value as of June 30, 2006. These fair values take into consideration the prevailing interest rate environment, the specific terms and conditions of a given transaction and any upfront payments that were received. All fair values were estimated using the zero-coupon discounting method. This method calculates the future payments required by the swap, assuming that the current forward rates implied by the yield curve are the market's best estimate of future spot interest rates. These payments are then discounted using the spot rates implied by the current yield curve for a hypothetical zero-coupon rate bond due on the date of each future net settlement on the swaps. While some of SCPPA's current mark to market values are negative, this valuation would be realized only if the swaps were terminated at the valuation date and only SCPPA retains the right to optionally terminate most of the transactions.

Note 4 - Derivative Instruments (Continued)

Credit risk - For each counterparty, except for the STS 2004 and the STS 2003 swaps, the net fair values of the Authority's applicable swaps as of June 30, 2006 were negative. However, should interest rates change and the fair values of the swaps become positive, the Authority may be exposed to credit risk in the amount of the derivatives' fair value.

The swap agreements contain varying collateral agreements with the counterparties. The swaps require full collateralization of the fair value of the swap should the counterparty's (or guarantors of the counterparty, as applicable) credit rating fall below AA- as issued by Standard & Poor's or Aa3 as issued by Moody's Investors Service for the 1991 Swap; A+/A1 for the 2004 Fixed Spread Basis Swap; A-/A3 for the 2001, the 2003 and the 2004 Swaps; and Baa1/BBB+ for the Swaption/Swap. Collateral on all swaps is to be in the form of U.S. government securities held by a third-party custodian.

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

Basis risk - Basis risk is the risk that the interest rate paid by the Authority on underlying variable rate bonds to bondholders exceeds the variable swap rate received from a counterparty. With the exception of the 1991 Swap, the Authority bears basis risk on each of its swaps. The 1991 Swap is perfectly hedged since the counterparty pays the Authority its actual variable bond rate on the 1991 bonds. All the other Swaps have a basis risk since under each of those swaps the Authority received a percentage of LIBOR (or BMA less 40 basis points) to offset the actual variable bond rate the Authority pays on any related bonds. The Authority is exposed to basis risk should the floating rate that it receives on a swap be less than the actual variable rate the Authority pays on any related bonds or in the case of the floating-to-floating fixed-spread basis swap, less than the variable rate paid to the swap counterparty.

Depending on the magnitude and duration of any basis risk shortfall, the expected cost savings from a swap may not be fully realized. The 2001 swap is based on BMA rate minus 40 basis points; similar to the LIBOR-based swaps, BMA minus 40 bps may not exactly hedge the underlying variable rate. As of June 30, 2006, the BMA rate, minus 40 bps, was 3.398%, whereas 60% of LIBOR was 3.065%, and 65% of LIBOR was 3.321%.

NOTES TO COMBINED FINANCIAL STATEMENTS (In Thousands)

Note 4 - Derivative Instruments (Continued)

The following is a summary of interest rates paid to and received from the counterparties as of June 30, 2006:

	Type of Derivative						
	1991 Swap	Swaption/ Swap	2001 Swap	2003 Swap	2004 Swap	MP 2004 Swap	MA 2004 Swap
Payments to counterparty	6.380%	4.250%	4.240%	3.266%	3.679%	3.894%	3.890%
Less, variable payments from counterparty	3.870%	3.065%	3.398%	3.335%	3.321%	3.321%	3.321%
Net interest rate swap payments	2.510%	1.185%	0.842%	-0.069%	0.358%	0.573%	0.569%
Add, variable-rate bond coupon payments	3.870%	N/A	3.920%	3.700%	N/A	3.800%	3.800%
Synthetic interest rate on bonds	6.380%	1.185%	4.762%	3.631%	0.358%	4.373%	4.369%

Termination risk - The Authority or the counterparty may terminate any of the swaps if the other party fails to perform under the terms of the contract. In addition, the 2001 Swap provides the counterparty with an option to cancel the swap agreement if the consecutive 180-day averaged rate of the BMA index exceeds 7.0%. However, the cancellation option has a 5-year lockout preventing the swap's termination prior to July 5, 2006. If any of the swaps were terminated, any associated variable rate bonds would no longer be hedged to a fixed rate. If at the time of termination the swap has a negative fair value, the Authority would be liable to the counterparty for a payment equal to the swap's fair value.

Rollover risk - Rollover risk is the risk that the swap contract is not co-terminus with the related bonds. The Authority is exposed to rollover risk on the 2001 swap because the counterparty has the option to terminate the agreement prior to the maturity of the associated debt. In the event that this swap terminates, the Authority would be exposed to variable interest rates on the underlying bonds. The following debt is exposed to rollover risk:

Associated Debt Issuance	Debt Maturity Date	Swap Termination Date
STS 2001 Subordinate Refunding Series A	July 1, 2021	July 1, 2021

NOTES TO COMBINED FINANCIAL STATEMENTS (In Thousands)

Note 4 - Derivative Instruments (Continued)

Swap payments and associated debt - Using rates as of June 30, 2006, debt service requirements of the Authority's outstanding variable rate debt and net swap payments are as follows. As rates vary, variable rate bond interest payments and net swap payments will vary.

	Variable-Rate Bonds		Interest Rate	
Fiscal Year Ending June 30,	Principal	Interest	Swaps, Net	Total
2007	1,950	25,362	9,857	35,219
2008	14,850	24,788	9,496	34,284
2009	15,775	24,178	9,112	33,290
2010	17,275	23,510	8,698	32,208
2011 - 2015	221,800	95,062	32,970	128,032
2016 - 2020	325,105	37,140	10,229	47,369
2021 - 2023	65,215	2,042	(38)	2,004
	$ 661,970	$ 232,082	$ 80,324	$ 312,406

Note 5 - Long-Term Debt

Long-term debt outstanding at June 30, 2006 consisted of "new money" bonds, refunding bonds and subordinate refunding bonds due in varying annual amounts through 2036. The new money bonds were issued to finance the purchase and construction or acquisition of the Authority's interest in each of the Projects. The subordinate refunding bonds were issued to refund specified new money bonds.

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

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

Note 5 - Long-Term Debt (Continued)

The Authority has agreed to certain covenants with respect to bonded indebtedness, including the requirement to enforce the natural gas, power and transmission sales agreements with the participants. At the option of the Authority, all outstanding new money bonds and refunding bonds are subject to redemption prior to maturity, except for the 1996 Subordinate Refunding Series A Bonds, the 2002 Subordinate Refunding Series B Bonds, and portions of the 1988A Refunding and 1992 Subordinate Refunding Bonds issued for the Southern Transmission System; the 2002A San Juan Revenue Bonds; and a total of $125.5 million of the Multiple Project Revenue Bonds.

Variable rate debt includes Auction Rate Certificates ("ARCs"), which bear interest at the applicable auction rate as determined by an Auction Agent, as well as debt with rates based on daily, weekly and long term rates as determined by a Remarketing Agent.

A summary of changes in long-term debt follows:

(Amounts in Thousands)

	Palo Verde Project	Southern Transmission System Project	Hoover Uprating Project	Mead- Phoenix Project	Mead-Adelanto Project	Multiple Project Fund	San Juan Project	Magnolia Power Project	Natural Gas Project	Total
Total long-term debt at June 30, 2005	$ 107,707	$ 777,888	$ 17,716	$ 65,934	$ 212,155	$ 202,104	$ 181,459	$ 320,909	$ -	$ 1,885,872
Total debt due within one year at June 30, 2005	11,300	31,470	1,275	-	-	8,100	9,160	-	-	61,305
Total debt at June 30, 2005	119,007	809,358	18,991	65,934	212,155	210,204	190,619	320,909	-	1,947,177
Principal payments	(11,300)	(31,470)	(1,275)	-	-	(170,200)	(9,160)	-	(1,700)	(225,105)
Revenue bonds issued	-	-	-	-	-	-	-	-	29,900	29,900
Decrease in unamortized debt-related costs, net	2,053	12,044	420	470	1,291	1,275	(174)	(434)	-	16,945
Total debt at June 30, 2006	109,760	789,932	18,136	66,404	213,446	41,279	181,285	320,475	28,200	1,768,917
Total debt due within one year at June 30, 2006	(11,545)	(34,230)	(1,315)	(3,250)	(10,850)	-	(9,570)	(3,735)	-	(74,495)
Total long-term debt at June 30, 2006	$ 98,215	$ 755,702	$ 16,821	$ 63,154	$ 202,596	$ 41,279	$ 171,715	$ 316,740	$ 28,200	$ 1,694,422

Palo Verde Project - Debt consists of subordinate refunding series bonds with variable interest rates and final maturities between 2009 and 2017.

Bonds Redeemed - In 1997, the Authority began taking steps designed to accelerate the payment schedule of all fixed rate subordinate bonds relating to the Palo Verde Nuclear Generating Station (PVNGS) so that they would be paid off by July 1, 2004 (the "Restructuring Plan"). Certain outstanding bonds were refunded for savings and the project participants accelerated payments on the bonds issued by the Authority for PVNGS. Accelerated payments were approximately $65 million per year from 1997 until final payment on July 1, 2004. The Plan resulted in substantial savings to the PVNGS project participants once the principal and interest on these fixed rate subordinate bonds were paid in full. As part of the Restructuring Plan, $512 million of debt was placed into legal defeasance as of July 1, 2004.

Southern Transmission System Project - Debt consists of refunding and subordinate refunding series bonds with fixed and variable interest rates. Fixed interest rates range from 3% to 6.125% and final maturities occur between 2006 and 2023.

Note 5 - Long-Term Debt (Continued)

Hoover Uprating Project - Debt consists of refunding series bonds with fixed interest rates between 3.5% and 5.25% and a final maturity during 2017.

Mead Phoenix Project - Debt consists of revenue and refunding series bonds with variable interest rates and a 5.15% fixed interest rate. Final maturity occurs during 2020.

Mead Adelanto Project - Debt consists of revenue and refunding series bonds with variable interest rates and a 5.15% fixed interest rate. Final maturity occurs during 2020.

Multiple Project Fund - Debt consists of revenue bonds with fixed interest rates ranging between 6.75% and 7.0% and final maturity during 2013.

Bonds Redeemed - On January 4, 1990, the Authority issued its Multiple Project Revenue Bonds, 1989 Series. Most of the proceeds of the Bonds were used to fund Authority projects, specifically the Mead-Phoenix and the Mead-Adelanto Transmission Projects. In April 2005, the Board determined that a portion of the remaining available proceeds should be used to redeem the callable bonds. In May 2005, the Authority's Board of Directors approved the redemption of $162.1 million of Multiple Projects Revenue Bonds, 1989 Series, representing all of the callable bonds. The bonds were redeemed on July 1, 2005.

San Juan Project - Debt consists of refunding series bonds with fixed interest rates between 4.5% and 5.5% and final maturities during 2014 and 2020.

San Juan Unit 3 Project Refunding - In April 2005, the Authority issued $71.88 million par value SJ 2005 Refunding Series A Bonds to refund all of the outstanding $71.85 million SJ 2002 Refunding Series B Bonds (the "refunded bonds"). This transaction resulted in a net loss for accounting purposes of $4.4 million, consisting primarily of the write-off of unamortized debt expenses and the premium associated with the refunded bonds. The loss on refunding of bonds was deferred and will be amortized in accordance with GASB 23 over the remaining life of the old debt or the life of the new debt, whichever is shorter.

San Juan completed the advanced refunding to reduce its total debt service payments over the refunding term by $9.9 million and to obtain an economic gain, measured as the difference between the present values of the old and new debt service payment requirements of $6.6 million.

Note 5 - Long-Term Debt (Continued)

Magnolia Power Project - Debt consists of revenue bonds with fixed interest rates between 2.00% and 5.25% with final maturities occurring in 2036.

Of the outstanding bonds, $14.1 million of "Project B Bonds" are secured by lease rental payments to be made by the City of Cerritos (the "City") in connection with the lease of certain facilities and premises owned by the City to the Authority and the leaseback of such facilities and premises to the City. The Base Rental Payments will be equal to the principal and interest on the Project B Bonds. In accordance with the Assignment Agreement between the Authority and the Trustee, the Authority will assign certain of its rights under the Lease, including its right to receive the Base Rental Payments, to the Trustee for the benefit of the Owners of the Project B Bonds.

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

Natural Gas Project - On July 1, 2005, the Authority issued taxable Natural Gas Project Revenue Bonds, Draw Down Series 2005A ("the Draw Down Bonds") at an interest rate of the one month LIBOR rate plus fifty basis points. The maximum amount that may be drawn and outstanding on the Draw Down Bonds is $100,000,000 and the initial draw was $26,300,100. The bonds were issued on behalf of Anaheim, Burbank and Colton to finance their share of the project. Additional draws may be used to increase the amount of natural gas to which the Natural Gas Project participants are entitled. As of June 30, 2006, the outstanding aggregate principal of the Draw Down Bonds was $28,200,100.

Debt Related Costs - Unamortized debt-related costs, net are as follows as of June 30, 2006 (amounts in thousands):

Unamortized debt-related costs, net	Loss on Refunding	(Premium) Discount	Total
Palo Verde Project	$ 15,500	$ -	$ 15,500
Southern Transmission System Project	97,397	21,021	118,418
Hoover Uprating Project	2,221	(272)	1,949
Mead-Phoenix Project	5,864	(363)	5,501
Mead-Adelanto Project	17,439	(1,716)	15,723
Multiple Project Fund	-	8,922	8,922
San Juan Project	6,879	(10,679)	(3,800)
Magnolia Power Project	-	(6,395)	(6,395)
	$ 145,300	$ 10,518	$ 155,818

NOTES TO COMBINED FINANCIAL STATEMENTS (In Thousands)

Note 5 - Long-Term Debt (Continued)

Debt Service - The scheduled debt service payments for future years ending June 30 are included in the table below. The variable rates used for the PV 1996 Subordinate Refunding Series B and C, and the STS 1996 Subordinate Refunding Series B were the rates at June 30, 2006 of 3.87% and 3.92%, respectively. The variable rates are set by the bond-remarketing agent on a weekly basis based on economic conditions and bond ratings. The variable rate used for the SJ 2002 Revenue Refunding Series B was assumed at 4% per annum starting in January 1, 2012.

	Palo Verde Project	Southern Transmission System Project	Hoover Uprating Project	Mead-Phoenix Project	Mead-Adelanto Project	Multiple Project Fund	San Juan Project	Magnolia Power Project	Natural Gas Project	Total
2007 Principal	11,545	34,230	1,315	3,250	10,850	-	9,570	3,735	-	74,495
2007 Interest	4,438	39,936	893	3,224	10,019	3,389	9,008	15,096	1,700	87,703
2008 Principal	11,895	30,950	1,370	3,350	11,150	-	10,050	4,520	28,200	101,485
2008 Interest	4,017	38,325	838	3,141	9,730	3,389	8,517	15,005	-	82,962
2009 Principal	12,250	31,550	1,425	3,425	11,400	-	10,550	4,610	-	75,210
2009 Interest	3,585	36,566	782	3,055	9,445	3,389	7,982	14,896	-	79,700
2010 Principal	10,075	30,880	1,480	3,500	11,725	-	11,115	4,720	-	73,495
2010 Interest	3,206	34,824	723	2,967	9,152	3,389	7,400	14,735	-	76,396
2011 Principal	10,375	33,115	1,540	4,560	12,540	11,400	11,715	4,880	-	90,125
2011 Interest	2,842	32,925	662	2,660	8,305	2,619	6,787	14,517	-	71,317
2012 - 2016 Principal	56,730	239,050	8,790	25,120	75,480	38,801	79,660	27,785	-	551,416
2012 - 2016 Interest	8,392	134,450	2,136	8,423	27,617	2,734	21,786	68,997	-	274,535
2017 - 2021 Principal	12,390	295,740	4,165	28,700	96,024	-	44,825	35,395	-	517,239
2017 - 2021 Interest	440	72,802	167	2,321	7,765	-	3,957	60,861	-	148,313
2022 - 2026 Principal	-	212,835	-	-	-	-	-	45,280	-	258,115
2022 - 2026 Interest	-	7,486	-	-	-	-	-	50,531	-	58,017
2027 - 2031 Principal	-	-	-	-	-	-	-	57,775	-	57,775
2027 - 2031 Interest	-	-	-	-	-	-	-	37,404	-	37,404
2032 - 2036 Principal	-	-	-	-	-	-	-	73,730	-	73,730
2032 - 2036 Interest	-	-	-	-	-	-	-	20,646	-	20,646
2037 Principal	-	-	-	-	-	-	-	51,650	-	51,650
2037 Interest	-	-	-	-	-	-	-	-	-	-
Principal	$ 125,260	$ 908,350	$ 20,085	$ 71,905	$ 229,169	$ 50,201	$ 177,485	$ 314,080	$ 28,200	$ 1,924,735
Interest	$ 26,920	$ 397,314	$ 6,201	$ 25,791	$ 82,033	$ 18,909	$ 65,437	$ 312,688	$ 1,700	$ 936,993

Fair Value - The fair value of the Authority's long-term debt (including the current portion) is approximately $2.0 billion and $2.2 billion at June 30, 2006 and 2005, respectively. Management has estimated fair value based on the quoted market prices for the same or similar issues or on the current average rates offered to the Authority for debt of approximately the same remaining maturities, excluding the effect of a related interest rate swap agreement.

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

Note 5 - Long-Term Debt (Continued)

Defeasance of Debt - The Authority has defeased specified revenue bonds by placing the proceeds from the issuance of subordinate refunding bonds in irrevocable trusts to provide for all future debt service payments on the refunded bonds. The trust investments and related liability for bonds that are considered legally defeased are not included in the Authority's financial statements. At June 30, 2006 and 2005, $702.5 million and $728.3 million, respectively, of revenue bonds outstanding are considered legally defeased.

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

Note 6 - Notes Payable

Notes payable consist mainly of Palo Verde Participants' over billings from prior periods and a note secured from GE Capital Public Finance, Inc., to lease purchased spare parts inventory for the Magnolia Power Project. The notes payable in the Palo Verde Project are to be paid through June 2017. These notes are unsecured, bear an interest rate of 4.97%, and are due in monthly payments of $636,000. At June 30, 2006, the remaining balance is $60 million. The note payable in the Magnolia Power Project has a coupon rate of 4.1%, with principal payments due monthly through July 2010. At June 30, 2006, the remaining principal balance is $5.1 million.

Note 7 - Net Assets (Deficit)

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

Note 7 - Net Assets (Deficit) (Continued)

Net assets (deficit) are comprised of the following (in thousands):

	June 30, 2004	Fiscal Year 2005 Activity	June 30, 2005	Fiscal Year 2006 Activity	June 30, 2006
GAAP items not included in billings to participants					
Depreciation of plant	$ (868,073)	$ (53,834)	$ (921,907)	$ (65,433)	$ (987,340)
Nuclear fuel amortization	(19,548)	-	(19,548)	-	(19,548)
Decommissioning expense	(137,264)	(14,013)	(151,277)	(13,269)	(164,546)
Amortization of bond discount, debt issue costs, and loss on refundings	(615,750)	(19,578)	(635,328)	(17,877)	(653,205)
Interest expense	(69,648)	(1,428)	(71,076)	5,479	(65,597)
Loss on defeasance of bonds	-	(85,827)	(85,827)	-	(85,827)
Bond requirements included in billings to participants					
Operations and maintenance, net of investment income	284,132	9,007	293,139	2,202	295,341
Costs of acquisition of capacity	18,698	(1,264)	17,434	(1,305)	16,129
Billings to amortize costs recoverable	382,050	-	382,050	-	382,050
Reduction in debt service billings due to transfer of excess funds	(90,020)	-	(90,020)	-	(90,020)
Principal repayments	862,521	49,397	911,918	70,212	982,130
Other	69,209	(13,511)	55,698	15,858	71,556
	(183,693)	(131,051)	(314,744)	(4,133)	(318,877)
Multiple Project Fund net assets	7,107	493	7,600	(1,848)	5,752
Projects' Stabilization Fund net assets	51,455	22,658	74,113	(7,520)	66,593
	$ (125,131)	$ (107,900)	$ (233,031)	$ (13,501)	$ (246,532)

Note 8 - Commitments and Contingencies

Industry Restructuring - Since the passage of Assembly Bill 1890 (the "Bill") in September 1996, the electric industry in California continues to remain uncertain. The deregulation experiment has, for the most part, been abandoned and the IOU situation is improving. The public power systems in the Authority were not required to comply with the Bill's provisions. They continued to plan for the needs of their customers and avoided customers choosing direct access and leaving the system. Most of the Authority's members have made investments in new gas-fired peaking or base-load generation located in Southern California. The members continue to collect the public benefit charge, and to date, have instituted in excess of $900 million of programs to benefit their customers. The decisions on how these funds are allocated are made by the local governing authority, in most cases this is the city council. Funds (approximately 2.95% of gross revenues) have been spent on renewable resources, conservation, research and development, and low income rate subsidies. The Authority cannot predict the impact of any future direct access or deregulation programs on energy markets or its participants.

Note 8 - Commitments and Contingencies (Continued)

Nuclear Spent Fuel and Waste Disposal - Under the Nuclear Waste Policy Act, the Department of Energy ("DOE") was to develop the facilities necessary for the storage and disposal of spent fuel and to have the first such facility in operation by 1998. That facility was to be a permanent repository, but the DOE has announced that such a repository could not be completed before 2010. There is ongoing litigation with respect to the DOE's ability to accept spent nuclear fuel and no permanent resolution has been reached to date.

In July 2002, a measure was signed into law designating the Yucca Mountain in the state of Nevada as the nation's high-level nuclear waste repository. This meant that the DOE could then file a construction and operation plan for Yucca Mountain with the Nuclear Regulatory Commission ("NRC"). The DOE expected that the Yucca Mountain site would be open by 2010. However, the State of Nevada and its congressional delegation are still determined to halt the project through the NRC process or through legal challenges.

Also a feud over funding of the repository ensued. The Administration and Congressional leaders pushed for full and adequate funding, in order for the DOE to meet the application deadline of 2004. Meanwhile, the Nevada delegation worked diligently to delay the DOE's work on the license application for the Yucca site, in hopes of halting the transfer of nuclear waste to the Nevada facility. As of today, the submission of the construction application to the NRC is still delayed because of an investigation related to the allegation of scientific misconduct during the feasibility study of Yucca Mountain as a permanent disposal facility for nuclear waste. In addition, the original regulatory standard of safe keeping nuclear waste at the disposal facility for 10,000 years was challenged by the National Academy of Sciences, and it is now agreed that the nuclear waste's storage period should increase to 100,000 years. Further engineering studies are being conducted to increase the subsistence of the facility for a longer period of time.

The spent fuel storage in the wet pool at PVNGS exhausted its capacity in 2003. A Dry Cask Storage Facility (the "Facility"), also called the Independent Spent Fuel Storage Facility, was built and completed in 2003 at a total cost of $33.9 million (about $2 million for the Authority). In addition to the Facility, the costs also account for heavy lift equipment inside the units and at the yard, railroad track, tractors, transporter, transport canister, and surveillance equipment. The Facility has the capacity to store all the spent fuel generated by the PVNGS plant until 2026. To date, over 43 casks, each containing 24 spent fuel assemblies were placed in the Facility. The current plan calls for the removal of between 240 and 288 fuel assemblies from the units to the Facility every year. The costs incurred by the procurement, packing, preparation and transportation of the casks are included as part of the fuel expenses, and will cost approximately $13 million a year (about $760,000 for the Authority). If the permanent repository in Yucca Mountain is opened as scheduled in 2010, the spent fuel from PVNGS will be shipped to the repository starting in 2031. No provision has been included in the accompanying financial statements.

Note 8 - Commitments and Contingencies (Continued)

Nuclear Insurance - The Price-Anderson Act (the "Act") requires that all utilities with nuclear generating facilities share in payment for claims resulting from a nuclear incident. The Act limits liability from third-party claims to approximately $10.8 billion per incident. Participants in the Palo Verde Nuclear Generating Station currently insure potential claims and liability through commercial insurance with a $300 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 $101 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 $15 million per reactor, per incident, per year to be indexed for inflation every 5 years. Based on the Authority's 5.91% interest in Palo Verde, the Authority would be responsible for a maximum assessment of $17.8 million, limited to payments of $2.7 million per incident, per year.

Other Legal Matters - With respect to the San Juan Generating Station (including the Authority's ownership interest in Unit 3 thereof), the Sierra Club and the Grand Canyon Trust have filed suit against Public Service Company of New Mexico ("PNM") in federal court alleging violations of the Clean Air Act and of the conditions of the San Juan Generating Station's operating permit. PNM is a co-owner of the San Juan Generating Station and is the operating agent of the station. The lawsuit sought penalties as well as injunctive and declaratory relief.

During 2005, the parties achieved a settlement of the substantive elements of the case which has been approved by the United States District Court. A number of environmental upgrades are being made to the San Juan Generating Station that is expected to mitigate a number of environmental consequences which might otherwise occur in the operation of the plant. The additional costs associated with these environmental upgrades will be shared by the San Juan Generation Station participants. The environmental upgrades affecting Unit 3 and the SCPPA San Juan participants are not anticipated to be added until approximately 2008. A current estimate which would be borne by the SCPPA San Juan Generating Station participants totals $32 million. SCPPA has already budgeted for the portion of the added costs of these upgrades which the SCPPA participants will bear. The upgrade expenditures of Unit 3 are not anticipated to occur until Spring 2008, and SCPPA is currently incorporating these costs into current and future budget projects. A liability has been established for $32 million and is presented as a deferred credit. The corresponding asset has been recorded as a deferred debit less cash already received from the participants.

Note 8 - Commitments and Contingencies (Continued)

Claims and a lawsuit for damages have been filed with the Authority, Intermountain Power Authority (the "IPA") and the LADWP seeking $100 million in special damages and a like amount in general damages. The claimants allege, among other things, that due to improper grounding of the transmission line of STS, their dairy herds were damaged and the value of their land was diminished. The claimants also seek injunctive relief. The Authority believed these claims were substantially without merit as to itself because the Authority has no ownership or operational control over the subject transmission lines, and merely acted as a financing agency with respect to STS. In July 2003, the Authority, IPA, and LADWP filed a motion to dismiss, or in the alternative, a motion to stay based upon forum non conveniens, in which the defendants argued that the case had little connection with California and should be heard in Utah. The Los Angeles Superior Court granted the motion and in a 2004 unpublished opinion the California Court of Appeal affirmed this matter on appeal. A Petition for Review was subsequently denied by the California Supreme Court.

In February 2005, the remaining Utah plaintiffs filed a complaint in the Third Judicial District Court in and for Salt Lake County, Utah, which alleged facts similar to those alleged in California. SCPPA has moved the Utah court to dismiss the action as to SCPPA; however, the motion has not yet come on for hearing before the Court. The motion to dismiss is currently stayed pending the determination for the Utah trial court whether to transfer the action from Salt Lake County to the District Court in Millard County Utah, where the Intermountain Power Project is located. No provision has been included in the accompanying financial statements.

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

Note 9 - Subsequent Events

Magnolia Power Project Revenue Bonds - In July 2006, the Authority issued $37.73 million par value Magnolia Power Project A, Revenue Bonds, Series 2006-1. The bonds, issued at a premium, generated $38.63 million of new money proceeds and received a True Interest Cost of 4.13% and a weighted average life of 5.797 years. The bonds were issued primarily for the purpose of completing the construction of the Magnolia Power Project.

Note 9 - Subsequent Events (Continued)

Interest Rate Amendment - In July 2006, the Authority executed an amendment to the Southern Transmission System Project $100 million, floating-to-floating Fixed-Spread basis swap entered into in 2004. Under the amended swap, SCPPA will continue to pay the swap counterparty the Bond Market Association ("BMA") index but will receive 58.99% of the 10-Year London Interbank Offered Rate ("LIBOR") plus 66.4 basis points, instead of 65% of 1-month LIBOR plus 66.4 basis points. The amended swap terms will become effective on August 1, 2007.

SUPPLEMENTAL INFORMATION

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
PALO VERDE PROJECT
SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS IN FUNDS REQUIRED BY THE BOND INDENTURE FOR THE YEAR ENDED JUNE 30, 2006
(AMOUNTS IN THOUSANDS)

	Debt Service Fund	Debt Service Reserve Fund	Decom-missioning Trust Fund	Deposit Installment	Deposit Reserve Installment	Escrow Account	General Reserve Account	Issue Account	Operating Account	Reserve & Contingency	Revenue Fund	Total
Balance at June 30, 2005	$ 4,003	$ 24	$ 133,094	$ 7	$ (3)	$ 428,398	$ -	$ 8,978	$ 88,554	$ 24,986	$ -	$ 688,041
Additions												
Investment earnings	60		4,825				7	82	3,960	684	9	9,627
Discount on investment purchases			42			16,459		292	93	51	5	16,942
Distribution of investment earnings	(60)			(7)	3	1,443	(7)	(374)	(727)	(735)	1,895	1,431
Revenue from power sales											49,277	49,277
Distribution of revenue	(4,062)	(24)						9,017	34,212	12,043	(51,186)	-
Transfer from escrow fund for principal and interest payments	3,209					(54,255)		51,046				-
Other												-
Total	(853)	(24)	4,867	(7)	3	(36,353)	-	60,063	37,538	12,043	-	77,277
Deductions												
Construction expenditures										12,722		12,722
Operating expenditures			2						30,083			30,085
Remarketing/commitment fees								371				371
Fuel costs									8,088			8,088
Payment of principal								11,300				11,300
Interest paid - non escrow								3,896	866			4,762
Premium and interest paid on investment purchases	(59)		(81)						121	68		49
Payment of principal and interest paid escrow	3,209							51,046				54,255
Total	3,150	-	(79)	-	-	-	-	66,613	39,158	12,790	-	121,632
Balance at June 30, 2006	$ -	$ -	$ 138,040	$ -	$ -	$ 392,045	$ -	$ 2,428	$ 86,934	$ 24,239	$ -	$ 643,686

This schedule summarizes the receipts and disbursements in funds required under the Bond Indenture and have been prepared from the trust statements. These balances do not include accrued interest receivable, unrealized gain (loss) on investments and $78 and $88 held in the revolving fund at June 30, 2006 and 2005, respectively.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
SOUTHERN TRANSMISSION SYSTEM PROJECT
SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS IN FUNDS REQUIRED BY THE BOND INDENTURE FOR THE YEAR ENDED JUNE 30, 2006
(AMOUNTS IN THOUSANDS)

	Debt Service Fund	Escrow Fund	Issue Fund	Operating Fund	Revenue Fund	Total
Balance at June 30, 2005	$ 4,655	$ 9,919	$ 73,496	$ 614	$ -	$ 88,684
Additions						
Investment earnings	4	-	2,866	4	12	2,886
Discount on investment purchases	30	3,156	400	53	23	3,662
Distribution of investment earnings	(34)	-	(3,266)	(57)	3,357	-
Revenue from transmission sales	-	-	-	-	84,135	84,135
Distribution of revenue	2,320	-	64,940	20,267	(87,527)	-
Transfer from escrow fund required by						-
refunding bonds issuance	4,200	(6,540)	2,340	-	-	-
Other transfers	-	-	-	-	-	-
Total	6,520	(3,384)	67,280	20,267	-	90,683
Deductions						
Operating expenses	-	-	-	19,807	-	19,807
Payment of principal	4,655	-	22,615	-	-	27,270
Interest and arbitrage paid	-	-	39,794	-	-	39,794
Principal and interest paid on escrow bonds	4,200	-	2,340	-	-	6,540
Total	8,855	-	64,749	19,807	-	93,411
Balance at June 30, 2006	$ 2,320	$ 6,535	$ 76,027	$ 1,074	$ -	$ 85,956

This schedule summarizes the receipts and disbursements in funds required under the Bond Indenture and have been prepared from the trust statements. These balances do not include accrued interest receivable, unrealized gain (loss) on investments and $34 and $38 held in the revolving fund at June 30, 2006 and 2005, respectively.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
HOOVER UPRATING PROJECT
SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS IN FUNDS REQUIRED BY THE BOND INDENTURE FOR THE YEAR ENDED JUNE 30, 2006
(AMOUNTS IN THOUSANDS)

	Debt Service Fund	General Reserve Fund	Advance Payment Fund	Operating Fund	Revenue Fund	Total
Balance at June 30, 2005	$ 1,171	$ 1,700	$ 3	$ 1,372	$ -	$ 4,246
Additions						
Investment earnings	6	51	-	21	2	80
Discount on investment purchases	26	-	-	29	-	55
Distribution of investment earnings	(32)	(51)	-	(50)	133	-
Revenue from power sales	-	-	-	-	2,351	2,351
Distribution of revenue	2,271	-	-	215	(2,486)	-
Other	-	3	(3)	-	-	-
Total	2,271	3	(3)	215	-	2,486
Deductions						
Operating expenses	-	-	-	271	-	271
Payment of principal	1,275	-	-	-	-	1,275
Interest paid	954	-	-	-	-	954
Total	2,229	-	-	271	-	2,500
Balance at June 30, 2006	$ 1,213	$ 1,703	$ -	$ 1,316	$ -	$ 4,232

This schedule summarizes the receipts and disbursements in funds required under the Bond Indenture and have been prepared from the trust statements. The balances in the funds consist of cash and investments at original cost. These balances do not include accrued interest receivable, unrealized gain (loss) on investments and $16 held in the revolving fund at both June 30, 2006 and 2005.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
MEAD-PHOENIX PROJECT
SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS IN FUNDS REQUIRED BY THE BOND INDENTURE FOR THE YEAR ENDED JUNE 30, 2006
(AMOUNTS IN THOUSANDS)

	Revenue Fund	Debt Service Account	Debt Service Reserve Account	Operating Fund	Reserve & Contingency Fund	Surplus Fund	Cost of Issuance Fund	Escrow Account	Total
Balance at June 30, 2005	$ -	$ 2,489	$ 5,915	$ 250	$ 1,231	$ 310	$ -	$ -	$ 10,195
Additions									
Investment earnings	2	120	435	6	90	3	-	-	656
Discount on investment earnings	-	16	-	3	-	17	-	-	36
Distribution of investment earnings	68	468	(435)	(4)	(90)	(7)	-	-	-
Transmission revenue	7,082	-	-	-	-	-	-	-	7,082
Distribution of revenues	(7,336)	5,277	-	1,254	16	789	-	-	-
Payments from Western Area Power Administration	154	-	-	-	-	-	-	-	154
Other transfers	30	-	-	-	-	-	-	-	30
Total	-	5,881	-	1,259	16	802	-	-	7,958
Deductions									
Construction expenditures	-	-	-	-	3	-	-	-	3
Operating expenses	-	-	-	1,230	-	-	-	-	1,230
Principal payment	-	-	-	-	-	-	-	-	-
Premium and interest paid on defeased bonds	-	-	-	-	-	-	-	-	-
Debt issuance costs	-	-	-	-	-	-	-	-	-
Interest paid	-	3,436	-	-	-	-	-	-	3,436
Total	-	3,436	-	1,230	3	-	-	-	4,669
Balance at June 30, 2006	$ -	$ 4,934	$ 5,915	$ 279	$ 1,244	$ 1,112	$ -	$ -	$ 13,484

This schedule summarizes the receipts and disbursements in funds required under the Bond Indenture and have been prepared from the trust statements. The balances in the funds consist of cash and investments at original cost. These balances do not include accrued interest receivable, unrealized gain (loss) on investments, and $12 held in the revolving fund at both June 30, 2006 and 2005.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
MEAD-ADELANTO PROJECT
SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS IN FUNDS REQUIRED BY THE BOND INDENTURE FOR THE YEAR ENDED JUNE 30, 2006
(AMOUNTS IN THOUSANDS)

	Debt Service Account	Debt Service Reserve Fund	Operating Fund	Reserve & Contingency	Revenue Fund	Surplus Fund	Escrow Account	Cost of Issuance Fund	Total
Balance at June 30, 2005	$ 3,814	$ 16,267	$ 713	$ 6,383	$ -	$ 672	$ -	$ -	$ 27,849
Additions									
Investment earnings	115	1,196	8	469	5	1	-	-	1,794
Discount on investment earnings	44	-	22	-	-	45	-	-	111
Distribution of investment earnings	1,411	(1,196)	(12)	(469)	284	(18)	-	-	-
Transmission revenue	-	-	-	-	20,669	-	-	-	20,669
Distribution of revenues	17,909	-	1,743	-	(20,955)	1,303	-	-	-
Payment from Western Area Power Administration	-	-	-	-	27	-	-	-	27
Other transfers	-	-	-	-	(30)	-	-	-	(30)
Total	19,479	-	1,761	-	-	1,331	-	-	22,571
Deductions									
Principal payment	-	-	-	-	-	-	-	-	-
Interest paid	10,653	-	-	-	-	-	-	-	10,653
Debt issuance costs	-	-	-	-	-	-	-	-	-
Operating expenses	-	-	1,508	-	-	-	-	-	1,508
Total	10,653	-	1,508	-	-	-	-	-	12,161
Balance at June 30, 2006	$ 12,640	$ 16,267	$ 966	$ 6,383	$ -	$ 2,003	$ -	$ -	$ 38,259

This schedule summarizes the receipts and disbursements in funds required under the Bond Indenture and have been prepared from the trust statements. The balances in the funds consist of cash and investments at original cost. These balances do not include accrued interest receivable, unrealized gain (loss) on investments and $10 held in the revolving fund at both June 30, 2006 and 2005.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
MULTIPLE PROJECT FUND
SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS IN FUNDS REQUIRED BY THE BOND INDENTURE FOR THE YEAR ENDED JUNE 30, 2006
(AMOUNTS IN THOUSANDS)

	Proceeds Account	Debt Service Account	Cost of Redemption Account	Total
Balance at June 30, 2005	$ 232,533	$ 1,340	$ -	$ 233,873
Additions				
Investment earnings	10,387	50	-	$ 10,437
Transfer of investment earnings to earnings account	(10,387)	10,387	-	-
Transfer to debt service account	(168,896)	168,896	-	-
Transfer from debt service account	1,340	(1,429)	89	-
Total	(167,556)	177,904	89	10,437
Deductions				
Interest paid	-	8,626	-	8,626
Payment of principal	-	8,100	-	8,100
Redemption of bonds	-	162,100	-	162,100
Cost of redemption	-	-	89	89
Total	-	178,826	89	178,915
Balance at June 30, 2006	$ 64,977	$ 418	$ -	$ 65,395

This schedule summarizes the receipts and disbursements in funds required under the Bond Indenture and have been prepared from the trust statements. The balances in the funds consist of cash and investments at original cost. These balances do not include accrued interest receivable.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
SAN JUAN PROJECT
SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS IN FUNDS REQUIRED BY THE BOND INDENTURE FOR THE YEAR ENDED JUNE 30, 2006
(AMOUNTS IN THOUSANDS)

	Acquisition Account	Debt Service Reserve Account	Revenue Fund	Operating Fund	Reserve & Contingency Fund	General Reserve Fund	Cost of Issuance Fund	Escrow Account	Total
Balance at June 30, 2005	$ 3,296	$ 21,323	$ -	$ 9,712	$ 11,386	$ -	$ 127	$ 78,454	$ 124,298
Additions									
Investment earnings	3	1,104	8	6	336	-	2	2,017	3,476
Discount on investments	151	-	12	240	240	-	-	-	643
Distribution of investment earnings	(154)	(1,104)	2,082	(246)	(576)	-	(2)	-	-
Revenue from power sales	-	-	70,039	-	-	-	-	-	70,039
Distribution of revenues	18,950	-	(72,141)	41,363	11,828	-	-	-	-
Bond proceeds	-	-	-	-	-	-	-	-	-
Transfer to escrow funds required by refunding bond issuance	-	-	-	-	-	-	-	-	-
Transfer from escrow fund for pricipal and interest payments	3,772	-	-	-	-	-	-	(3,772)	-
Other	-	-	-	-	-	31	(31)	-	-
Total	22,722	-	-	41,363	11,828	31	(31)	(1,755)	74,158
Deductions									
Operating expenses	-	-	-	45,013	-	-	-	-	45,013
Construction expenses	-	-	-	-	5,421	-	-	-	5,421
Payment of principlal and interest - escrow	3,772	-	-	-	-	-	-	-	3,772
Premium and interest on investment purchases	-	-	-	-	11	-	-	-	11
Payment of principal	9,160	-	-	-	-	-	-	-	9,160
Debt issueance costs	-	-	-	-	-	-	97	-	97
Interest paid - non-escrow	8,461	-	-	-	-	-	-	-	8,461
Total	21,393	-	-	45,013	5,432	-	97	-	71,935
Balance at June 30, 2006	$ 4,625	$ 21,323	$ -	$ 6,062	$ 17,782	$ 31	$ (1)	$ 76,699	$ 126,521

This schedule summarizes the receipts and disbursements in funds required under the Bond Indenture and have been prepared from the trust statements. The balances in the funds consist of cash and investments at original cost. These balances do not include accrued interest receivable, unrealized gain (loss) on investments, and $22 held in the revolving fund at both June 30, 2006 and 2005.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
MAGNOLIA POWER PROJECT
SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS IN FUNDS REQUIRED BY THE BOND INDENTURE FOR THE YEAR ENDED JUNE 30, 2006
(AMOUNTS IN THOUSANDS)

	Debt Service Account	Debt Service Reserve Account	Project Fund	Operating Reserve Fund	Reserve and Contingency	Operating Fund	Revenue Fund	Total
Balance at June 30, 2005	$ 6,478	$ 20,013	$ 13,180	$ 4,993	$ 9,793	$ -	$ 69	$ 54,526
Additions								
Investment earnings	8	471	34	7	-	7	11	538
Discount on investment purchases	92	2	89	210	84	757	10	1,244
Distribution of investment earnings	(98)	(278)	(1)	(147)	-	(724)	1,248	-
Transfer of funds for debt service payment	1,211	-	(1,211)	-	-	-	-	-
Receipt from participants	-	-	-	-	-	-	83,941	83,941
Distribution of revenues	18,801	1	3,096	9	-	63,372	(85,279)	-
Transfer to project fund	-	(586)	11,986	(74)	(9,779)	(1,547)	-	-
MPC Transfer	-	-	-	-	-	-	-	-
Other	-	-	4	-	-	-	-	4
Total	20,014	(390)	13,997	5	(9,695)	61,865	(69)	85,727
Deductions								
Construction expenditures	-	-	25,531	-	-	-	-	25,531
Operating expenses	-	-	-	-	-	47,000	-	47,000
Premium and interest on investment purchases	-	4	-	83	98	-	-	185
Interest paid - non-escrow	15,170	-	-	-	-	-	-	15,170
Total	15,170	4	25,531	83	98	47,000	-	87,886
Balance at June 30, 2006	$ 11,322	$ 19,619	$ 1,646	$ 4,915	$ -	$ 14,865	$ -	$ 52,367

This schedule summarizes the receipts and disbursements in funds required under the Bond Indenture and have been prepared from the trust statements. The balances in the funds consist of cash and investments at original cost. These balances do not include accrued interest receivable, unrealized gain (loss) on investments and $14 held in the revolving fund at both June 30, 2006 and 2005.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
NATURAL GAS PROJECT
SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS IN FUNDS REQUIRED BY THE BOND INDENTURE FOR THE YEAR ENDED JUNE 30, 2006
(AMOUNTS IN THOUSANDS)

	Revenue Fund	Operating Fund	Fund	General Reserve Fund	Project Fund	Capital Fund	Depository Fund	Total
Balance at June 30, 2005	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Additions								
Investment earnings	2	21	4	-	4	7	9	47
Discount on investment purchases	-	156	30	-	20	9	6	221
Distribution of investment earnings	-	3	-	-	-	2	(5)	-
Bond Proceeds 2005A	-	-	-	-	29,900	-	-	29,900
Receipt from participants	5,763	24,342	-	-	-	19,128	-	49,233
Distribution of revenues	(5,765)	2,676	3,360	-	(2,147)	1,985	(109)	-
Other	-	1,537	-	-	-	205	23,738	25,480
Total	-	28,735	3,394	-	27,777	21,336	23,639	104,881
Deductions								
Acquisition of gas reserves	-	-	-	-	25,963	-	23,245	49,208
Development and completion costs	-	-	-	-	21	19,727	209	19,957
Operating expenses	-	18,735	-	-	-	-	185	18,920
Payment of principal	-	-	1,700	-	-	-	-	1,700
Interest paid	-	-	1,186	-	-	-	-	1,186
Debt issuance costs	-	-	-	-	214	-	-	214
Total	-	18,735	2,886	-	26,198	19,727	23,639	91,185
Balance at June 30, 2006	$ -	$ 10,000	$ 508	$ -	$ 1,579	$ 1,609	$ -	$ 13,696

This schedule summarizes the receipts and disbursements in funds required under the Bond Indenture and have been prepared from the trust statements. The balances in the funds consist of cash and investments at original cost. These balances do not include accrued interest receivable, unrealized gain (loss) on investments, and $14 held in the revolving fund at both June 30, 2006.

KPMG

LOS ANGELES DEPARTMENT OF WATER AND POWER
POWER SYSTEM

Basic Financial Statements and
Required Supplementary Information

June 30, 2006 and 2005

(With Independent Auditors' Report Thereon)

LOS ANGELES DEPARTMENT OF WATER AND POWER
POWER SYSTEM

Basic Financial Statements and
Required Supplementary Information

June 30, 2006 and 2005

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KPMG LLP
Suite 2000
355 South Grand Avenue
Los Angeles, CA 90071-1568

Independent Auditors' Report

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

We have audited the accompanying balance sheets 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 June 30, 2006 and 2005, and the related statements of revenues, expenses, and changes in fund net assets and cash flows for the years then ended. These financial statements are the responsibility of the Los Angeles Department of Water and Power's (the Department) management. Our responsibility is to express an opinion on these financial statements based on our audits. The partial 2004 comparative information has been derived from the Power System's 2004 financial statements which were audited by other auditors whose report dated December 9, 2005 included explanatory paragraphs that described the adoption of Governmental Accounting Standards Board Statements No. 39, *Determining Whether Certain Organizations are Component Units*, Statement No. 42, *Accounting and Financial Reporting for Impairment of Capital Assets and for Insurance Recoveries,* Statement No. 45, *Accounting and Financial Reporting by Employers for Postretirement Benefits Other Than Pensions*, and the restatement of the Power System's June 30, 2004 financial statements.

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 of material misstatement. An audit includes consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Power System's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and the significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in note 1, the financial statements present only the financial position of 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, 2006 and 2005, the changes in its financial position and its cash flows for the years ended June 30, 2006, 2005, and 2004, in conformity with U.S. generally accepted accounting principles.

In our opinion, the 2006 and 2005 financial statements referred to above present fairly, in all material respects, the financial position of the Power System, as of June 30, 2006 and 2005, and the changes in its financial position and its cash flows for the years then ended in conformity with U.S. generally accepted accounting principles.

In accordance with *Government Auditing Standards*, we have also issued our report dated November 7, 2006 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 the internal control over financial reporting or on compliance. That report is an integral part of an audit performed in accordance with *Government Auditing Standards* and should be considered in assessing the results of our audits.

The management's discussion and analysis included on pages 3 through 12 and the schedules of funding progress for the pension plan and postretirement health care plan on pages 53 (note 12(d)) and 61 are not a required part of the basic financial statements but are supplementary information required by U.S. generally accepted accounting principles. We have applied certain limited procedures, which consisted principally of inquiries of management regarding the methods of measurement and presentation of the required supplementary information. However, we did not audit the information and express no opinion on it.

KPMG LLP

November 7, 2006

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 (Power System), provides an overview of the financial activities for the fiscal years ended June 30, 2006 and 2005. 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 13.

Using This Financial Report

This annual financial report consists of the basic 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.

Balance Sheets, Statements of Revenues, Expenses, and Changes in Net Assets, and Statements of Cash Flows

The basic financial statements provide an indication of the Power System's financial health. The balance sheets include all of the Power System's assets and liabilities, 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 fund net assets report all of the revenues and expenses during the time periods indicated. The statements of cash flows report the cash provided and used by operating activities, as well as other cash sources such as investment income, cash payments for bond principal, and capital additions and betterments.

The following table summarizes the financial condition and changes in fund net assets of the Power System as of and for the fiscal years ended June 30, 2006, 2005, and 2004:

Table 1 – Summary of Financial Condition and Changes in Fund Net Assets

(Amounts in millions)

		June 30,		
Assets		**2006**	**2005**	**2004**
Utility plant, net	$	5,709	5,299	5,165
Restricted investments		955	1,036	978
Other noncurrent assets		1,362	1,307	1,360
Current assets		1,720	1,314	1,241
	$	9,746	8,956	8,744
Liabilities and Fund Net Assets				
Long-term debt, net of current portion	$	4,262	3,481	3,357
Other long-term liabilities		710	732	610
Current liabilities		662	681	726
		5,634	4,894	4,693
Fund net assets:				
Invested in capital assets, net of related debt		1,774	1,641	1,664
Restricted		1,159	1,482	1,218
Unrestricted		1,179	939	1,169
Total fund net assets		4,112	4,062	4,051
	$	9,746	8,956	8,744

(Continued)

Table 1 (Continued)

(Amounts in millions)

Revenues, Expenses, and Changes in Fund Net Assets		Year ended June 30, 2006	2005	2004
Residential	$	759	693	718
Commercial and industrial		1,545	1,421	1,461
Sales for resale		153	102	74
Other		39	39	35
Total operating revenues		2,496	2,255	2,288
Fuel for generation and purchased power		1,283	1,113	1,096
Maintenance and other operating expenses		1,004	969	939
Total operating expenses		2,287	2,082	2,035
Operating income		209	173	253
Nonoperating activity:				
Investment income		123	113	92
Other nonoperating revenues and expenses, net		13	5	17
Debt expenses		(167)	(146)	(134)
Income before capital contributions, transfers, and extraordinary items		178	145	228
Capital contributions		30	26	39
Transfer to the reserve fund of the City of Los Angeles		(158)	(160)	(210)
Extraordinary loss on extinguishment of debt		—	—	(6)
Increase in fund net assets		50	11	51
Beginning balance of fund net assets		4,062	4,051	3,693
Adjustment due to change in accounting principle from SFAS No. 106 to GASB No. 45		—	—	307
Ending balance of fund net assets	$	4,112	4,062	4,051

Assets

Utility Plant

During fiscal years 2006 and 2005, the Power System put into service $331 million and $607 million, respectively, of additions, including transfers from construction work in progress to utility plant in service. Of the $331 million, $186 million, or 56.0%, related to distribution plant assets. In addition, during 2006, the Power System capitalized $61 million related to generation assets. Of the $607 million in 2005, $403 million, or 66.0%, related to generation plant assets. The majority of these additions were incurred as part of the Power System's Integrated Resource Plan. Furthermore, the Power System had capital improvements to its transmission and distribution utility plant assets to maintain and support normal load growth of the distribution and transmission systems.

Construction work in progress increased by $136 million in 2006 and decreased by $218 million in fiscal year 2005. The increase in 2006 was mostly attributable to the Pinetree Wind Project and other generation improvements. The decrease in 2005 was primarily as a result of ongoing local generation projects under the Integrated Resource Plan being placed in commercial service.

The Department's strategy is to have generating utility plant assets that can produce energy from a variety of fuel types. This is referred to as a hedged power supply. This is important in that if the costs related to a particular fuel type rise substantially in a short period of time, the Department can utilize its mix of generation assets to meet customer demand and to minimize increases in fuel expense. The Department has implemented a $2 billion, ten-year plan to upgrade its local power plants and to implement a program that includes demand side management, alternative energy sources, and distributed generation. Through June 30, 2006, the Department has incurred $1.3 billion related to such upgrades.

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

On July 1, 2005, the Power System and other members of the Southern California Public Power Authority (SCPPA) completed the acquisition of natural gas reserves and other real property located in Pinedale, Wyoming. The transaction totaled in excess of $300 million, of which the Power System contributed approximately $230 million. This is the first natural gas reserves acquisition for the Power System. Additional information regarding the natural gas field can be found in note 1 in the accompanying notes to the financial statements.

The table below summarizes the generating resources available to the Department as of June 30, 2006. 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 2 – Generation Resources

Resource type	Number of units		Net maximum capacity (MWs)	Net * dependable
Steam:				
Gas	22		3,421	3,354
Coal	5		1,621	1,621
Nuclear	3		374	367
Large Hydro	8	**	1,666	1,535
Renewable	28		255	202
EE, DSM, DG ***	1		46	46
Subtotal	67		7,383	7,125
Typical CDWR obligation****			(65)	(65)
Total			7,318	7,060

* Capacity that the thermal units can obtain during varying types of weather conditions, less the energy needed to power normal auxiliaries in service.
** Hoover Plant Station is counted as one unit and seven Castaic units.
*** EE, DSM, DG refer to energy efficiency, demand-side management and distributed generation.
**** Energy payable to the California Department of Water Resources (CDWR).

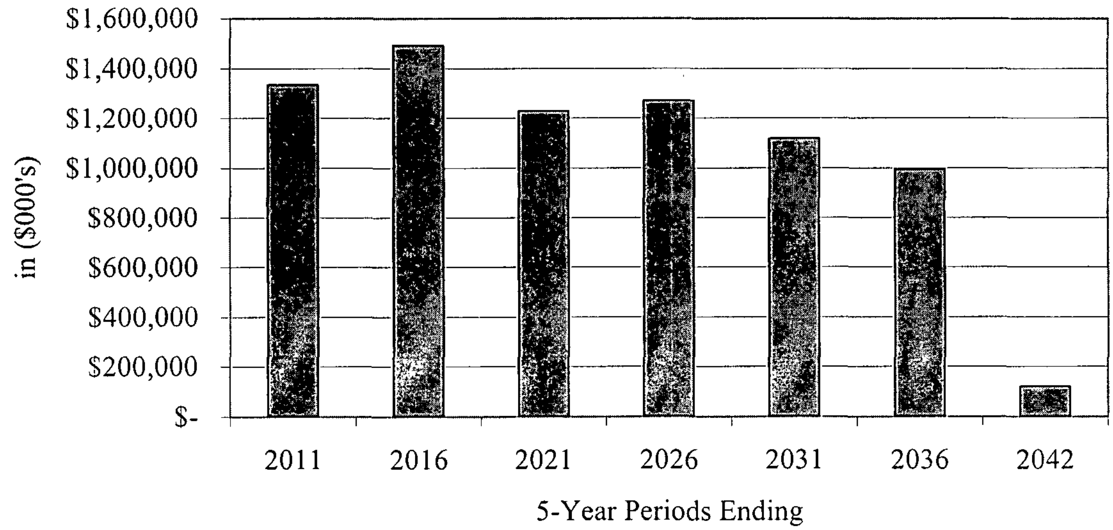
Liabilities and Fund Net Assets

Long-Term Debt

As of June 30, 2006, the Power System's total long-term debt balance was $4.45 billion. The increase of $793 million over the prior year resulted primarily from the net effect of the issuance of $932 million in revenue bonds, scheduled maturities of $56 million, and the defeasance of $116 million of Power System revenue bonds.

Outstanding principal, plus scheduled interest as of June 30, 2006, is scheduled to mature as shown in the chart below:

Chart 1: Debt Service Requirements



As of June 30, 2006, $179 million principal amount of long-term debt is considered defeased and remains outstanding. This debt, together with assets in trust funds set aside for its full repayment at scheduled maturity dates, is not reflected on the balance sheet.

In addition, the Power System had $451 million and $601 million on deposit in trust funds restricted for the use of debt reduction as of June 30, 2006 and 2005, respectively.

During fiscal year 2006, 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, sound financial metrics, and significant progress on economically defeasing one-half of the Power System's off-balance sheet commitments. Additional information regarding the Power System's long-term debt can be found in note 10 in the notes to the financial statements.

Changes in Fund Net Assets

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 3 summarizes the percentage contribution of retail revenues from each customer segment in fiscal years 2006 and 2005.

Table 3 – Operating Revenues and Percent of Revenue By Customer Class

(Amounts in thousands)

	Fiscal Year 2006		Fiscal Year 2005	
Customer type	Revenue	Percent	Revenue	Percent
Residential	$ 758,932	32.0%	$ 693,559	32.0%
Commercial	1,320,870	56.0	1,223,230	57.0
Industrial	223,985	10.0	197,773	9.0
Other	39,122	2.0	38,714	2.0
Total retail revenue	$ 2,342,909	100.0%	$ 2,153,276	100.0%

While commercial customers consume the most electricity, residential customers represent the largest customer class. As of June 30, 2006 and 2005, the Power System had approximately 1.4 million customers. As shown in Table 4, 1.2 million, or 86.0%, of total customers were in the residential customer class.

Table 4 – No. of Customers and Percent of Customers By Customer Class

(in thousands)

	Fiscal Year 2006		Fiscal Year 2005	
Customer type	Number	Percent	Number	Percent
Residential	1,242	86.0%	1,237	86.0%
Commercial	186	13.0	183	13.0
Industrial	14	1.0	14	1.0
Other	3	—	3	—
	1,445	100.0%	1,437	100.0%

Fiscal Year 2006

Retail revenues increased $189.6 million and wholesale revenues increased $51 million, respectively, from fiscal year 2005. The increase in retail revenue is mostly due to discontinuing the deferral of revenue collected for out-of-market purchased power costs and beginning to recognize prior deferred amounts. The increase in wholesale revenue is due to increased sales activity in both the forward and real-time energy and capacity markets.

Fiscal Year 2005

Wholesale revenues increased from 2004 while retail revenues in all customer classes decreased from fiscal year 2004 due to a decrease in consumption. The decrease is mostly due to milder weather. The increase in wholesale revenue is due to increased sales from 2004.

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 purchase 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 5.0% 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 years.

The tables below summarize the Power System's operating expenses during fiscal years 2006 and 2005:

Table 5 – Operating Expenses and Percent of Expense By Type of Expense

(Amounts in thousands)

	Fiscal Year 2006		Fiscal Year 2005	
Type of expense	**Expense**	**Percent**	**Expense**	**Percent**
Fuel for generation	$ 541,659	23.7%	$ 478,201	23.0%
Purchased power	741,810	32.4	634,923	30.5
Other operating costs	472,394	20.7	484,905	23.3
Maintenance	260,217	11.4	237,565	11.4
Depreciation and amortization	270,841	11.8	246,597	11.8
	$ 2,286,921	100.0%	$ 2,082,191	100.0%

(Continued)

Fiscal Year 2006

Fiscal year 2006 operating expenses were $205 million higher as compared to fiscal year 2005. Fuel for generation expense increased by $63 million due to higher cost of natural gas. Purchased power costs increased due to economic purchases being made. Economic purchases are purchases of energy on the open market where the Department has determined that the cost of acquiring the energy is less expensive than using available generation resources to meet customer demand.

Maintenance and deprecation increased by $23 million and $24 million, respectively. The increase in maintenance was due to addition work being performed on transmission assets. The increase in deprecation was due to additional assets being placed in service. These increases were offset by a decrease in other operating costs related to distribution assets.

Fiscal Year 2005

Fiscal year 2005 operating expenses were $47 million higher as compared to fiscal year 2004. Fuel for generation expense increased by $44 million due to higher cost of natural gas, and other operating and maintenance expenses increased by $61 million due to increased labor costs, including pension expense. These increases were offset by decreases in purchased power costs and depreciation expense.

Depreciation expense decreased during fiscal year 2005 as compared to fiscal year 2004, mainly due to the implementation of the 2003 Depreciation Study. The Depreciation Study was adopted in the fourth quarter of 2004. The decrease was offset by additional depreciation in the current year as a result of additions to utility plant.

Nonoperating Revenues and Expenses

Fiscal Year 2006

The major nonoperating activities of the Power System for fiscal year 2006 included the transfer of $157.9 million to the City's General Fund, income earned on investments of $123 million, and $167.5 million in debt expenses.

The transfer to the City is based on 7.0% of the previous year's operating revenues. Operating revenues for fiscal year 2005 were $2.3 billion, which generated a City transfer of $157.9 million.

Investment income increased $10 million due to interest rates trending higher in fiscal year 2006 as compared to 2005.

The increase in debt expense is due to the issuance $932 million of revenue bonds and higher interest rates on variable rate debt. The variable rate bonds' daily and weekly rate range increased from 2.22% to 2.27% as of June 30, 2005 to 3.94% to 3.95% as of June 30, 2006.

Fiscal Year 2005

The major nonoperating activities of the Power System for fiscal year 2005 included the transfer of $160 million to the City's General Fund, income earned on investments of $113 million, and $147 million in debt expenses.

The transfer to the City is based on 7.0% of the previous year's operating revenues. Operating revenues for fiscal year 2004 were $2.3 billion, which generated a City transfer of $160 million.

Investment income increased $21 million due to interest rates trending higher in fiscal year 2005 as compared to 2004.

The increase in debt expense is due to the issuance $200 million of revenue certificates in September 2004 and higher interest rates on variable rate debt. The variable rate bonds' daily and weekly rate range increased from 1.06% to 1.13% as of June 30, 2004 to 2.22% to 2.27% as of June 30, 2005.

Investment income decreased in fiscal year 2004 due to a $175 million reduction in investments and interest rates following the general trend and decreasing during fiscal year 2004.

Interest on debt declined due to lower rates on variable rate debt and the effects of the debt restructuring program, which lowered average interest rates on fixed rate debt.

Other Significant Matters

On August 16, 2006, the City Council approved the unfreezing of the energy cost adjustment factor. This change took effect October 1, 2006.

On September 19, 2006, the Board of Water and Power Commissioners (the Board) approved the creation of a Retiree Health Benefits Fund to be maintained by the Retirement Plan Office. During fiscal year 2007, the assets held by both the Water and the Power System will be transferred to this newly created fund. This transfer will reduce the Power System's restricted investments and restricted fund net assets.

LOS ANGELES DEPARTMENT OF WATER AND POWER
POWER SYSTEM

Balance Sheets

June 30, 2006 and 2005

(Amounts in thousands)

Assets		2006	2005
Noncurrent assets:			
Utility plant:			
Generation	$	3,444,102	3,385,763
Transmission		906,848	871,968
Distribution		4,288,601	4,114,437
General		948,407	987,556
		9,587,958	9,359,724
Accumulated depreciation		(4,701,006)	(4,508,330)
		4,886,952	4,851,394
Construction work in progress		570,418	434,105
Nuclear fuel, at amortized cost		14,578	13,472
Natural gas field, net		237,403	—
		5,709,351	5,298,971
Restricted investments		955,340	1,036,114
Long-term California wholesale energy receivable, net		116,367	116,438
Long-term notes and other receivables, net of current portion		1,144,941	1,075,482
Net pension asset		99,793	114,521
Total noncurrent assets		8,025,792	7,641,526
Current assets:			
Cash and cash equivalents – unrestricted		315,298	145,367
Cash and cash equivalents – restricted		731,205	405,561
Cash collateral received from securities lending transactions		73,509	192,799
Customer and other accounts receivable, net of allowance for losses of $33,432 in 2006 and $30,872 in 2005		280,723	247,832
Current portion of long-term notes receivable		32,887	45,000
Accrued unbilled revenue		140,386	125,277
Materials and fuel		112,107	117,202
Prepayments and other current assets		33,948	35,295
Total current assets		1,720,063	1,314,333
Total assets	$	9,745,855	8,955,859

See accompanying notes to financial statements.

LOS ANGELES DEPARTMENT OF WATER AND POWER
POWER SYSTEM

Balance Sheets (continued)

June 30, 2006 and 2005

(Amounts in thousands)

Fund Net Assets and Liabilities		2006	2005
Fund net assets:			
Invested in capital assets, net of related debt	$	1,774,252	1,641,388
Restricted:			
Debt service		600,750	721,928
Capital projects		97,017	323,596
Other postemployment benefits		231,496	199,914
Pension benefits		99,793	114,521
Other purposes		129,304	121,564
Unrestricted		1,178,955	938,775
Total fund net assets		4,111,567	4,061,686
Long-term debt, net of current portion		4,261,748	3,480,712
Other noncurrent liabilities:			
Deferred credits		564,164	625,555
Net other postemployment benefit obligation		110,823	71,168
Accrued workers' compensation claims		35,558	35,558
Commitments and contingencies (notes 6 and 15)			
Total other noncurrent liabilities		710,545	732,281
Current liabilities:			
Current portion of long-term debt		188,821	176,871
Accounts payable and accrued expenses		223,434	160,007
Accrued interest		80,249	62,365
Accrued employee expenses		82,575	71,730
Due to Water System		13,407	17,408
Obligation under securities lending transactions		73,509	192,799
Total current liabilities		661,995	681,180
Total liabilities		5,634,288	4,894,173
Total liabilities and fund net assets	$	9,745,855	8,955,859

See accompanying notes to financial statements.

LOS ANGELES DEPARTMENT OF WATER AND POWER
POWER SYSTEM

Statements of Revenues, Expenses, and Changes in Fund Net Assets

Years ended June 30, 2006, 2005, and 2004

(Amounts in thousands)

		2006	2005	2004
Operating revenues:				
Residential	$	758,932	693,559	717,912
Commercial and industrial		1,544,855	1,421,003	1,460,814
Sales for resale		153,480	102,357	73,959
Other		50,579	48,275	49,682
Uncollectible accounts		(11,457)	(9,561)	(14,271)
		2,496,389	2,255,633	2,288,096
Operating expenses:				
Fuel for generation		541,659	478,201	434,122
Purchased power		741,810	634,923	662,070
Maintenance and other operating expenses		732,611	722,470	661,404
Depreciation and amortization		270,841	246,597	264,126
Loss on asset impairment and abandoned projects		—	—	13,634
		2,286,921	2,082,191	2,035,356
Operating income		209,468	173,442	252,740
Nonoperating revenues (expenses):				
Investment income		122,734	112,780	91,849
Other nonoperating income		17,394	9,695	21,066
		140,128	122,475	112,915
Other nonoperating expenses		(4,246)	(4,164)	(3,967)
		135,882	118,311	108,948
Debt expenses:				
Interest on debt		(170,839)	(148,347)	(135,793)
Allowance for funds used during construction		3,339	1,618	1,903
		(167,500)	(146,729)	(133,890)
Income before capital contributions, transfers, and extraordinary item		177,850	145,024	227,798
Capital contributions		29,925	25,896	38,514
Transfers to the reserve fund of the City of Los Angeles		(157,894)	(160,167)	(210,214)
Extraordinary loss on extinguishment of debt		—	—	(5,624)
Increase in fund net assets		49,881	10,753	50,474
Fund net assets:				
Beginning of year		4,061,686	4,050,933	3,693,062
Adjustment due to change in accounting principle from SFAS No. 106 to GASB No. 45 (note 2)		—	—	307,397
End of year	$	4,111,567	4,061,686	4,050,933

See accompanying notes to financial statements.

LOS ANGELES DEPARTMENT OF WATER AND POWER
POWER SYSTEM

Statements of Cash Flows

Years ended June 30, 2006, 2005, and 2004

(Amounts in thousands)

	2006	2005	2004
Cash flows from operating activities:			
Cash receipts:			
Cash receipts from retail customers	$ 2,326,817	2,286,794	2,306,676
Cash receipts from retail customers for other agency services	349,767	345,361	289,096
Cash receipts from wholesale customers	118,910	57,902	96,988
Cash receipts from interfund services provided	286,947	325,848	286,023
Other cash receipts	14,671	626	—
Cash disbursements:			
Cash payments to employees	(431,114)	(421,955)	(388,834)
Cash payments to suppliers	(1,462,463)	(1,296,277)	(1,374,458)
Cash payments for interfund services used	(342,519)	(363,321)	(396,332)
Cash payments to other agencies for fees collected	(319,998)	(323,399)	(302,871)
Other cash payments	—	—	(11,101)
	541,018	611,579	505,187
Cash flows from noncapital financing activities:			
Payments to the reserve fund of the City of Los Angeles	(157,894)	(220,167)	(179,214)
Interest paid on noncapital revenue bonds	(17,060)	(10,391)	(5,402)
	(174,954)	(230,558)	(184,616)
Cash flows from capital and related financing activities:			
Additions to plant and equipment, net	(677,882)	(378,867)	(547,527)
Capital contributions	12,186	16,813	45,477
Proceeds from escrow investment maturities	—	—	34,262
Principal payments and maturities on long-term debt	(172,600)	(46,228)	(1,125,282)
Proceeds from issuance of bonds and revenue certificates	956,171	199,832	1,222,461
Debt interest payments	(133,831)	(137,247)	(115,458)
	(15,956)	(345,697)	(486,067)
Cash flows from investing activities:			
Purchases of investment securities	(2,122,855)	(2,547,736)	(4,026,043)
Sales and maturities of investment securities	2,214,078	2,538,717	4,129,278
Purchase of long-term notes receivable	(92,385)	—	—
Proceeds from notes receivable	44,999	61,081	64,453
Investment income	101,630	112,430	102,106
	145,467	164,492	269,794
Net increase in cash and cash equivalents	495,575	199,816	104,298
Cash and cash equivalents:			
Cash and cash equivalents at July 1 (including $405,561, $162,762, and $120,742 reported in restricted accounts, respectively)	550,928	351,112	246,814
Cash and cash equivalents at June 30 (including $731,205, $405,561, and $162,762 reported in restricted accounts, respectively)	$ 1,046,503	550,928	351,112

See accompanying notes to financial statements.

LOS ANGELES DEPARTMENT OF WATER AND POWER
POWER SYSTEM

Statements of Cash Flows (continued)

Years ended June 30, 2006, 2005, and 2004

(Amounts in thousands)

		2006	2005	2004
Reconciliation of operating income to net cash provided by operating activities:				
Operating income	$	209,468	173,442	252,740
Adjustments to reconcile operating income to net cash provided by operating activities:				
Depreciation and amortization		270,841	246,597	264,126
Provision for losses on customer and other accounts receivable		11,457	9,561	14,271
Loss on asset impairment and abandoned projects		—	—	13,634
Provision for obsolete inventory		11,500	—	—
Changes in assets and liabilities:				
Customer and other accounts receivable		(25,843)	(16,738)	(20,445)
Accrued unbilled revenue		(15,108)	5,249	(11,674)
Materials and fuel		(6,405)	(8,486)	2,521
Net pension asset		14,728	7,750	(3,073)
Accounts payable and accrued expenses		63,427	(5,377)	(46,777)
Deferred credits		(61,391)	85,412	73,975
Due (from) to Water System		(4,001)	37,415	(68,588)
Net other postemployment benefit liability		39,655	25,269	38,065
Workers' compensation liability and other		32,690	51,485	(3,588)
Net cash provided by operating activities	$	541,018	611,579	505,187

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 (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. Prior to fiscal year 2003, the Department applied all statements issued by the Governmental Accounting Standards Board (GASB) and all statements and interpretations issued by the Financial Accounting Standards Board (FASB), which are not in conflict with statements issued by GASB. In fiscal year 2003, the Department changed its election under the guidance in GASB Statement No. 20, *Accounting and Financial Reporting for Proprietary Funds and Other Governmental Entities that Use Proprietary Fund Accounting* (GASB No. 20), to follow all GASB statements and only FASB statements and interpretations issued on or before November 30, 1989 (see note 2).

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 City Council. As a regulated enterprise, the Department utilizes Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulation* (SFAS No. 71), 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 fund net assets. Accordingly, the Power System records various regulatory assets and liabilities to reflect the Board's actions. Regulatory liabilities were recorded in deferred credits and regulatory assets were included as prepayments on the balance sheets. Management believes that the Power System meets the criteria for continued application of SFAS No. 71, but will continue to evaluate its applicability based on changes in the regulatory and competitive environment (see note 3).

(b) Use of Estimates

The preparation of financial statements in conformity with U.S. generally accepted accounting principles 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, health care 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. The original cost of property retired, net of removal and salvage costs, is charged to accumulated depreciation.

During fiscal year 2004, the Power System reversed previously capitalized postretirement health care costs of $70 million from utility plant assets, net. These costs were capitalized as construction charges as a component of labor expenses determined under SFAS No. 106, *Employer's Accounting for Postretirement Benefits Other Than Pensions* (SFAS No. 106). As a result of the adoption of GASB Statement No. 45, *Accounting and Financial Reporting by Employees for Postemployment Benefit Other Than Pensions* (GASB No. 45) these costs were eliminated.

(d) *Impairment of Long-Lived Assets*

Effective fiscal year 2004, the Department adopted GASB Statement No. 42, *Accounting and Financial Reporting for Impairment of Capital Assets and for Insurance Recoveries* (GASB 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 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 (see notes 2 and 15).

(e) *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 years. Depreciation and amortization expense as a percentage of average depreciable utility plant in service were 3.0%, 2.8%, and 3.2% for each of the fiscal years ended 2006, 2005, and 2004, respectively.

(Continued)

(f) Nuclear Decommissioning

The Department owns a 5.7% direct ownership interest in the Palo Verde Nuclear Generating Station (PVNGS). In addition, through its participation in the Southern California Public Power Authority (SCPPA), the Department is party to a contract for an additional 3.95% of the output of PVNGS. Nuclear decommissioning costs associated with the Power System's output entitlement are included in purchased power expense (see note 6).

Decommissioning of PVNGS is expected to commence subsequent to the year 2024. The total cost to decommission the Power System's direct ownership interest in PVNGS is estimated to be $130 million in 2004 dollars. This estimate is based on an updated site-specific study prepared by an independent consultant in 2004. As of June 30, 2006 and 2005, the Power System has recorded $116.6 million and $115.3 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 Nuclear Regulatory Commission 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 into the decommissioning trusts. The Department reinvested $1.3 million and $4.4 million of investment income in fiscal years 2006 and 2005, respectively. Decommissioning funds, which are included in restricted investments, totaled $97.0 million and $95.7 million as of June 30, 2006 and 2005 (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.

(g) 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's $1 per megawatt hour of nuclear generation. The Power System includes this charge as a current year expense in fuel for generation. See note 15 for discussion of spent nuclear fuel disposal.

(h) 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 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 producing gas properties are depleted by the unit-of-production method based on the estimated future production of the proven and developed producing wells.

Depletion expense related to the gas field is recorded as a component of fuel for generation expense. During fiscal year 2006, the Power System recorded $12.9 million of depletion expense.

(i) *Cash and Cash Equivalents*

As provided for by the California Government 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 fund net assets. 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 on the balance sheets. The Department considers its portion of pooled investments with an original maturity of three months or less to be cash equivalents.

At June 30, 2006 and 2005, restricted cash and cash equivalents include the following (amounts in thousands):

		June 30,	
		2006	2005
Bond redemption and interest funds	$	149,308	122,079
Construction funds		515,471	54
Self-insurance fund		63,862	52,475
Funds for purchase of gas field		—	227,791
Other		2,564	3,162
	$	731,205	405,561

(j) *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.

(k) *Accrued Unbilled Revenue*

Accrued unbilled revenue is the receivable for estimated energy sales during the period for which the customer has not yet been billed.

(l) *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 fund net assets, 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).

(m) ***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, 2006 and 2005 (amounts in thousands):

		Balance as of June 30,	
		2006	2005
Type of expenses:			
Accrued payroll	$	31,178	24,112
Accrued vacation		35,125	33,100
Accrued sick time		8,399	7,709
Compensatory time		7,873	6,809
Total	$	82,575	71,730

(n) ***Debt Expenses***

Debt premium, discount, and issue expenses are deferred 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 on debt using the effective-interest method over the shorter of the life of the new bonds or the remaining term of the bonds refunded. Gains and losses on bond defeasances financed with cash are reported as an extraordinary gain or loss on extinguishment of debt in the accompanying statements of revenues, expenses, and changes in fund net assets.

(o) ***Gas and Electricity Option and Location Swap Agreements***

Gas and electricity option and location swap agreements were previously reported at fair value on the balance sheets. With the change in election under GASB No. 20, the Department now accounts for these contracts on a settlement basis (see note 9).

(p) ***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 (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 Water System is responsible for collection, maintenance, and refunding of these deposits for all Department customers, including those of the Power System. As such, the Water System's balance sheets include a deposit liability of $67.9 million and $59.3 million as of June 30, 2006 and 2005, 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 owing to 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 other City 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.

Operating revenues are revenues generally derived from activities that are billable in accordance with the electric rate ordinance approved by the City Council.

(s) ***Capital Contributions***

Capital contributions (formally referred to as contributions in aid of construction) 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***

Allowance for funds used during construction (AFUDC) 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. The average AFUDC rate was 4.6%, 3.3%, and 4.9% for each of fiscal years 2006, 2005, and 2004, respectively.

(u) ***Use of Restricted and Unrestricted 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.

(v) ***Comparative Information***

The financial statements include partial 2004 comparative information. Such information does not include all of the information and disclosures required for a complete set of basic financial statements. Accordingly, such information should be read in conjunction with the Power System's financial statements for the year ended June 30, 2004, from which such partial comparative information was derived.

(w) ***Reclassifications***

Certain financial statement items for 2005 have been reclassified to conform to the 2006 presentation.

(Continued)

(2) Accounting Changes

(a) GASB Statement No. 40

Effective July 1, 2004, the Department adopted GASB Statement No. 40, *Deposit and Risk Investment Disclosures, an amendment of GASB Statement No. 3* (GASB No. 40). GASB No. 40 requires specific disclosures, if applicable, for credit risk, concentration of credit risk, interest rate risk, and foreign currency risk. It also modifies GASB Statement No. 3, *Deposits with Financial Institutions, Investments (including Repurchase Agreements), and Reverse Purchase Agreements*, related to required disclosures of custodial credit risk to one category of deposits and investments. See note 7 for disclosures.

(b) GASB Statement No. 45

On July 1, 2003, the Department adopted GASB Statement No. 45, *Accounting and Financial Reporting by Employers for Postemployment Benefits Other Than Pensions* (GASB No. 45), and discontinued following SFAS No. 106, *Employers' Accounting for Postretirement Benefits Other Than Pensions* (SFAS No. 106).

The Power System does not administer its plan for postretirement benefits other than pensions (health care benefits) as a trust or equivalent arrangement. The Power System has not established the plan as a separate legal entity or documented the plan's objectives and parameters, the duties and responsibilities of the plan's governing body, or the plan retirees' and beneficiaries' rights that would require a legal separation of employer and plan assets and liabilities. While certain assets that will fund liabilities of the plan have been placed into an irrevocable trust and can only be used to pay for plan liabilities on behalf of the Power System, current postretirement benefit payments are not made from the trust, and as such, under the requirements of GASB No. 45, they are not considered contributions of the plan. Therefore, the assets placed into the trust remain restricted Power System assets and are reported as such in the accompanying balance sheets as of June 30, 2006 and 2005. Currently, retiree premium payments are made from the Power System's operations. Further, separate financial statements of the plan are not prepared. See note 12 for a description of the plan.

Prior to July 1, 2003, the Department was applying SFAS No. 106 in accounting for other postretirement costs. The postretirement obligation at June 30, 2003 amounted to $362 million. The adoption of GASB No. 45 allows the Department to set the beginning postretirement obligation to zero and reverse any previously reported obligation. To eliminate the Power System's postretirement liability, management reviewed the charges for health care costs created by SFAS No. 106 and reversed the costs as of July 1, 2003. Costs were reversed from previous capitalized labor charges included in utility plant and other operating expenses recorded in prior fiscal years.

The change from SFAS No. 106 to GASB No. 45 had no change to the health plan benefits to active or retired employees. The change also did not affect the assets designated for postretirement benefits. The change from SFAS No. 106 to GASB No. 45 changed the postretirement liability as of July 1, 2003, the determination of the annual required funding contribution for subsequent fiscal years, and the actuarial accrued liability (see note 12).

As a result of the adoption of GASB No. 45, the following adjustments were recorded to the Power System's balance sheet as of July 1, 2003 (dollar amounts in thousands):

Balance sheet item		Reported as of June 2003	Adjustments	Adjusted balance
Generation assets	$	2,622,137	(4,109)	2,618,028
Transmission assets		829,457	(7,761)	821,696
Distribution assets		3,893,836	(64,375)	3,829,461
General assets		915,054	(8,675)	906,379
Accumulated depreciation		(4,073,466)	14,880	(4,058,586)
Prepayments and other current assets		95,635	(3,370)	92,265
Due to Water System		(67,447)	18,867	(48,580)
Accrued postretirement liability/asset		(230,693)	361,940	131,247
Fund net assets		(3,693,062)	(307,397)	(4,000,459)

With the adoption of GASB No. 45, the Department's postretirement annual required contribution for both the Power System and Water System decreased from $119.7 million in fiscal year 2003 under SFAS No. 106 to $107 million in fiscal year 2004 under GASB No. 45. The difference was due to a change in the discount rate from 5.75% to 6.5%, a change in the actuarial cost method from the projected unit credit cost method to the entry age normal cost method, and a change in the amortization period for prior service costs from 20 to 30 years. See note 12 for the required information under GASB No. 45.

Of the $107 million postretirement annual required contribution recorded under GASB No. 45, $70.9 million was allocated to the Power System. The Power System paid $32.4 million for retiree premiums during fiscal year 2004, leaving $38.5 million as a liability on the Power System's books as of June 30, 2004.

The Power System has established a restricted investment trust for postretirement health care expenses. These monies are restricted assets on the Power System's balance sheets. In 2004, the Department made additional contributions to the postretirement investment trust. As a result, the postretirement obligation and restricted investments on the Power System's books as of June 30, 2004 is as follows (amounts in thousands):

		June 30, 2004
Postretirement liability	$	(38,487)
Restricted investments – postretirement trust assets		197,670

(c) ***GASB Statement No. 42***

In November 2003, GASB issued GASB Statement No. 42, *Accounting and Financial Reporting for Impairment of Capital Assets and for Insurance Recoveries* (GASB No. 42). This statement established accounting and financial reporting standards for impairment of capital assets. In fiscal year 2004, the Power System early adopted GASB No. 42 and calculated the impairment to its Mohave Generating Station and a procurement system. No retroactive restatement was required. See note 15 for a discussion on the impairment.

(d) ***GASB Statement No. 39***

As of July 1, 2003, the Power System adopted GASB Statement No. 39, *Determining Whether Certain Organizations are Component Units* (GASB No. 39). This statement amends GASB Statement No. 14, *The Financial Reporting Entity* (GASB No. 14) to provide additional guidance to determine whether certain organizations for which the primary government is not financially accountable should be reported as component units, based on the nature and significance of their relationship with the primary government. Generally, it requires reporting, as a component unit, an organization that raises and holds economic resources for the direct benefit of a governmental unit. The Power System is an enterprise fund of the City of Los Angeles and will continue to be included as part of the City's comprehensive annual financial report. As part of the adoption of GASB No. 39, the Department reviewed its relationships between the Power System and the Intermountain Power Agency, and the Southern California Public Power Authority. Neither of these relationships met the component unit requirements of GASB No. 39. As a result, there was no material impact to the Power System's financial statements as a result of adopting this statement. This Statement was effective for the Power System beginning in fiscal year 2004.

(3) Regulatory Matters

Effective April 1, 1998, customers of California's investor-owned utilities (IOU) became eligible for direct access. The introduction of direct access resulted in significant structural changes to the electric power industry, including plant divestitures and management of IOU transmission assets through the California Independent System Operator (CAISO). In 2001, legislation was enacted to suspend direct access to retail customers in California. No definitive plan for allowing direct access to customers in the Department's service area has been adopted; however, if the Department implements direct access in the future, it is likely that its generation business will no longer qualify for accounting under SFAS No. 71. SFAS No. 71 requires that the effects of the rate making process be recorded in the financial statements.

As a government-owned utility, the Department was not compelled to participate in direct access or to divest its generation assets. Management has implemented debt and cost reduction programs and restructured certain purchase power commitments in response to the changes in the electric utility market. Furthermore, in August 2000, the City Council approved a $1.7 billion, ten-year plan to upgrade the Department's local power plants and to implement a program that includes demand-side management, renewable energy sources, and distributed generation. The plan was redrafted in 2006 to incorporate the Power System's goal of increasing its portion of renewable energy sales to 20.0% by 2010. This plan has been amended to allow for a total budget of $2.0 billion, and as of June 30, 2006, the Department has incurred $1.3 billion related to such upgrades.

(a) *Federal Energy Regulatory Commission Price Mitigation Plan*

In June 2001, the Federal Energy Regulatory Commission (FERC) issued a price mitigation plan on spot market sales in the Western Electric Coordinating Council (WECC). The plan imposes price limits on the sale of electricity in WECC based on a calculation that estimates the cost of production of the least efficient gas-fired generation plant in California and a fixed factor to account for other variable costs. The Power System's purchases and sales of electricity occur entirely within the WECC and, as such, are subject to these measures. These measures have, in part, contributed to stabilizing the market and resulting in overall lower wholesale prices.

(b) *California Receivables and FERC Refund Hearings*

During fiscal year 2001, the Power System made sales to two California agencies that were formed by Assembly Bill 1890 to facilitate the purchase and sale of energy and ancillary services in the state of California. Through June 30, 2006, these agencies, the CAISO, and the California Power Exchange (CPX), have made minimal payments since April 2001 on amounts outstanding to counterparties, including the Power System, for certain energy purchases in fiscal years 2000 and 2001. The CPX filed for protection under Chapter 11 of the Federal Bankruptcy Statute in January 2001. Pacific Gas & Electric and Southern California Edison Company have paid all amounts due to the CPX; however, the amounts remain in an escrow account pending the resolution of disbursement of the funds.

As of June 30, 2006 and 2005, a total of $166.5 million was due to the Power System from the CAISO and the CPX. The FERC has questioned whether amounts charged for energy sold to the CAISO and the CPX during 2000 and 2001 represent "unlawful profits" that should be subject to refund. The FERC has considered various options for determination of a refund amount but has not issued definitive guidance on what represents unlawful profits for sales during the period. The Courts have opined that FERC has no jurisdiction over the Department; however, the Courts have stated that the California parties seeking the refund may have a cause of action. As such, the litigation in this area is continuing.

The Power System has recorded a $50.0 million liability as of June 30, 2006 and 2005 against the $166.5 million receivable, for potential refunds pertaining to its wholesale sales during 2000 and 2001. Management believes that this is the most probable amount that will be refunded by the Power System and is based on the most recent formula disclosed by FERC. While management has recorded its estimate of the most probable amounts that will be refunded, management does believe that it is entitled to all amounts due from sales to counterparties in California, including those named above. Furthermore, management believes that interest may be due to it on those amounts but any potential receivable is not estimable at this time. In addition, management does not believe that the Power System's exposure to any additional losses with respect to these receivable balances is currently estimable. If final settlement of these receivables results in an amount less than the recorded balance, net of the $50.0 million liability recorded, the Department will be required to record a loss in future periods.

(c) *Public Benefits*

In accordance with Assembly Bill 1890, as amended by Assembly Bill 995 and pursuant to direction from the Board, a percentage of the Department's retail revenue is designated for use for qualifying public benefit programs. Qualifying programs include cost-effective demand-side management services to promote energy efficiency and energy conservation, new investment in renewable energy resources and technologies, development and demonstration programs to advance science and technology, and services provided for low-income electricity customers. In accordance with current legislation and the Department's plans, the program is currently expected to cease on January 1, 2012.

The Department defers public benefit revenue from customers in excess of costs incurred under qualifying programs and defers qualifying expenses in excess of collections pursuant to approval received from the Board. During fiscal years 2006, 2005, and 2004, the Department spent $50.6 million, $39.2 million, and $64.2 million, respectively, on public benefits programs. These programs include investments in electric buses and vehicles, photovoltaics, or solar power and other alternative energy sources, and support for low-income and life-support customers. As of June 30, 2006 and 2005, the Department has recorded a deferred credit in the amount of $25.3 million and $12.7 million due to public benefit expenses below revenues, respectively. Regulatory liabilities are reduced when adequate public benefit expenses are incurred, and regulatory assets are recovered when the corresponding revenue is earned.

(d) *State Legislation*

On September 12, 2002, Senate Bill 1078 was enacted, which requires, among other things, the IOUs to generate 20.0% of their electricity from renewable energy sources, such as wind, solar, biomass, and geothermal energy, by no later than 2017. Publicly owned utilities such as the Department are exempt from the direct provisions of this California law and must establish their own renewable portfolio standard considering the intent of the Legislature.

(e) *Federal Regulation of Transmission Access*

The Energy Policy Act of 1992 (the Energy Policy Act) made fundamental changes in the federal regulation of the electric utility industry, particularly in the area of transmission. As amended by the Energy Policy Act, Sections 211, 212, and 213 of the Federal Power Act provide FERC authority, upon application by any electric utility, federal power marketing agency, or other person or entity generating electric energy for sale or resale, to require a transmitting utility to provide transmission services (including any enlargement of transmission capacity necessary to provide such services) to the applicant at rates, charges, terms, and conditions set by FERC based on standards and provisions in the Federal Power Act (FPA). Under the Energy Policy Act, electric utilities owned by municipalities and other public agencies which own or operate electric power transmission facilities which are used for the sale of electric energy at wholesale are "transmitting utilities" subject to the requirements of Sections 211, 212, and 213.

FERC has adopted a "go slow" approach to the issue of RTO formation in the western United States; it is contemporaneously engaged in a wholesale overhaul of the California market design, referred to initially as the "MDO2 proceeding" and more recently as the "MRTU proceeding." These FERC proceedings will have potential impacts on every electric utility doing business in California. It is not certain at this time what impact, if any, FERC's final decision on MDO2 or MRTU proceedings will have on the Power System or when FERC will issue a final order. In addition, the California ISO has announced its intention to implement further market changes over the next five years.

(f) Federal Energy Legislation

On August 8, 2005, the Energy Policy Act of 2005 (the Act) was enacted, the first comprehensive energy legislation in over a decade. One of the most significant provisions of the Act repeals the Public Utility Holding Company Act of 1935 (PUHCA) six months after the effective date of the Act, on February 8, 2006. PUHCA prevented investment in the public utility sector by entities such as financial institutions and industrial companies, and was a barrier to consolidation within the industry through its requirement that merged companies operate within a single region.

Another significant provision of the Act empowers FERC to certify an Electric Reliability Organization (ERO) to improve the reliability of the "bulk-power system" through mandatory and enforceable electric reliability standards (in contrast to the current voluntary system). The definition of "bulk-power system" does not include facilities used in the local distribution of electric energy. The ERO will file any proposed reliability standard or modification with FERC. A "reliability standard" is a requirement that provides for 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 facilities or to construct new transmission or generation. 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.

The Act authorizes FERC to require nondiscriminatory access to transmission facilities owned by municipal, cooperative, and other transmission companies not currently regulated by FERC, unless exercising this authority would violate a private activity bond rule for purposes of Section 141 of the Internal Revenue Code of 1986. FERC is prohibited from requiring any such entities to join RTOs. The Act also allows FERC to issue permits for the construction of new transmission facilities when states have been unable or unwilling to act, and allows load-serving entities to use the firm transmission rights, or equivalent tradable or financial transmission rights, in order to deliver output or purchased energy to the extent required to meet its service obligations. The Act does not relieve a load-serving entity from any obligation under state or local law to build transmission or distribution facilities adequate to meet its service obligations, or to abrogate preexisting firm transmission service contracts.

The Act directs FERC to establish, by rule, incentive-based rates for transmission no later than August 2006, and requires FERC to establish market transparency rules for the electric wholesale market (entities that have a "de minimis market presence" are exempt from the rules). The Act instructs that the market transparency rules must provide for the timely dissemination of information about the availability and prices of wholesale electric energy and transmission service to FERC, state commission, buyers and sellers of wholesale electric energy, users of transmission services, and the public. Within 180 days of the Act's enactment, FERC and the Commodity Futures Trading Commission are required to enter into a memorandum of understanding regarding information sharing pursuant to these rules.

In addition, the Act prohibits any person from willfully and knowingly reporting false information to any federal agency on the price of wholesale electricity or availability of transmission capacity, or using (directly or indirectly) any manipulative device in contravention of any FERC rule. The Act increases civil and criminal penalties, modifies the procedures for review of FERC orders under the FPA, and changes the refund date under the FPA to be effective as of the date an applicable complaint is filed. The Act also establishes an entity's right to a refund if (i) it makes a short-term sale of electric energy through an organized market in which the rates for the sale are set by a FERC-approved tariff (not by a contract) and (ii) the sale violates the terms of the tariff or applicable FERC rule in effect at the time of the sale.

The Act contains provisions for $800 million in tax-credit bonds (which pay no interest but instead provide tax credits) to be issued in 2006 and 2007 to finance renewable energy projects for nonprofit utilities. No more than $500 million of these bonds, however, may be issued for projects for governmental entities.

The overall impact of the Act on the Department cannot be predicted at this time.

(4) Utility Plant

The Power System had the following activity in utility plant during fiscal year 2006 (amounts in thousands):

	Balance June 30, 2005	Additions	Retirements and disposals	Transfers	Balance June 30, 2006
Nondepreciable utility plant:					
Land and land rights	$ 148,568	6,619	(10,566)	—	144,621
Construction work in progress	434,105	324,694	—	(188,381)	570,418
Nuclear fuel	13,472	6,306	(5,200)	—	14,578
Natural gas field	—	250,342	(12,939)	—	237,403
Total nondepreciable utility plant	596,145	587,961	(28,705)	(188,381)	967,020
Depreciable utility plant:					
Generation	3,376,741	27,926	(8,666)	33,567	3,429,568
Transmission	792,262	797	(895)	37,332	829,496
Distribution	4,070,937	78,343	(11,733)	107,524	4,245,071
General	971,216	35,831	(77,803)	9,958	939,202
Total depreciable utility plant	9,211,156	142,897	(99,097)	188,381	9,443,337
Less accumulated depreciation:					
Generation	(1,835,185)	(107,409)	7,677	—	(1,934,917)
Transmission	(340,535)	(16,806)	183	96	(357,062)
Distribution	(1,676,710)	(109,044)	1,384	(3)	(1,784,373)
General	(655,900)	(35,537)	66,876	(93)	(624,654)
Total accumulated depreciation	(4,508,330)	(268,796)	76,120	—	(4,701,006)
Total utility plant, net	$ 5,298,971	462,062	(51,682)	—	5,709,351

Depreciation and amortization expense during fiscal 2006 was $270.8 million.

The Power System had the following activity in utility plant during fiscal year 2005 (amounts in thousands):

	Balance June 30, 2004	Additions	Retirements and disposals	Transfers	Balance June 30, 2005
Nondepreciable utility plant:					
Land and land rights	$ 157,788	25	(9,245)	—	148,568
Construction work in progress	652,375	219,572	—	(437,842)	434,105
Nuclear fuel	12,553	6,119	(5,200)	—	13,472
Total nondepreciable utility plant	822,716	225,716	(14,445)	(437,842)	596,145
Depreciable utility plant:					
Generation	2,980,568	28,646	(6,480)	374,007	3,376,741
Transmission	775,855	12,732	(10)	3,685	792,262
Distribution	3,946,432	68,679	(1,331)	57,157	4,070,937
General	925,754	52,714	(10,245)	2,993	971,216
Total depreciable utility plant	8,628,609	162,771	(18,066)	437,842	9,211,156
Less accumulated depreciation:					
Generation	(1,745,948)	(95,717)	6,480	—	(1,835,185)
Transmission	(324,677)	(15,868)	10	—	(340,535)
Distribution	(1,573,735)	(104,306)	1,331	—	(1,676,710)
General	(641,883)	(24,262)	10,245	—	(655,900)
Total accumulated depreciation	(4,286,243)	(240,153)	18,066	—	(4,508,330)
Total utility plant, net	$ 5,165,082	148,334	(14,445)	—	5,298,971

Depreciation and amortization expense during fiscal 2005 was $246.6 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, 2005 and 2006, utility plant includes the following amounts related to the Power System's' ownership interest in each jointly owned utility plant (amounts in thousands, except as indicated):

	Ownership interest	Share of capacity (MWs)	Utility plant in service June 30, 2006 Cost	Utility plant in service June 30, 2006 Accumulated depreciation	Utility plant in service June 30, 2005 Cost	Utility plant in service June 30, 2005 Accumulated depreciation
Palo Verde Nuclear Generating Statioı	5.7%	217	$ 546,915	284,929	529,634	270,898
Navajo Generating Station	21.2	477	318,440	243,618	315,739	230,093
Mohave Generating Station	10.0	158	70,136	68,619	69,681	68,510
Pacific Intertie DC Transmission Line	40.0	1,240	211,709	66,690	204,003	62,660
Other transmission systems		Various	77,598	39,897	77,010	37,912
			$ 1,224,798	703,753	1,196,067	670,073

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

The Power System has entered into a number of energy and transmission service contracts, which involve substantial commitments as follows (amounts in thousands, except as indicated):

	Agency	Agency share	Power System's interest in agency's share Interest	Power System's interest in agency's share Capacity MWs	Power System's interest in agency's share Outstanding principal
Intermountain Power Project	IPA	100.0%	63.9%	1,121	$ 1,451,044
Palo Verde Nuclear Generating Station	SCPPA	5.9	67.0	151	83,924
Mead-Adelanto Project	SCPPA	68.0	36.0	291	81,826
Mead-Phoenix Project	SCPPA	17.8 – 22.4	25.0	148	17,881
Southern Transmission System	SCPPA	100.0	60.0	1,142	540,777

IPA: The Intermountain Power Agency 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, a California Joint Powers Agency. Note: SCPPA's interest in the Mead-Phoenix Project includes three components.

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 $301 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 $316 million annually during each of the next five years). The Power System made total payments under these agreements of approximately $433 million, $468 million, and $551 million in fiscal years 2006, 2005, and 2004, respectively. These agreements are scheduled to expire from 2027 to 2030.

The Power System earned fees under the IPP Project Manager and Operating Agent agreements totaling $16.9 million, $16.3 million, and $18.2 million in fiscal years 2006, 2005, and 2004, 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 $1.17 billion and $1.12 billion as of June 30, 2006 and 2005, respectively.

(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 Power System's share of capacity at Hoover is approximately 500 megawatts. The cost of power purchased under this contract was $13 million, $13 million, and $12 million in each of fiscal years 2006, 2005, and 2004, respectively.

(7) Cash, Cash Equivalents, and Investments

(a) Restricted and Other Investments

A summary of the Power System's restricted investments is as follows (amounts in thousands):

Description		June 30, 2006	2005
Restricted and other investments:			
Restricted investments:			
Debt reduction trust funds	$	450,561	601,130
Postretirement health care benefit trust		342,319	271,082
Nuclear decommissioning trust fund		97,017	95,750
Natural gas trust fund		25,043	25,022
SCPPA Palo Verde investment		40,400	43,094
Other investments		—	36
Total restricted investments		955,340	1,036,114
Other investments:			
Cash collateral received from the Department's securities lending transactions* (see note 8)		—	155,481
Total restricted and other investments	$	955,340	1,191,595

* The Power System also has $73,509 and $37,318 of cash collateral received from securities lending transactions in the City' s securities lending program, respectively, (see notes 7(b) and 8).

All restricted and other investments are to be used for a designated purpose as follows:

i. *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.

ii. *Postretirement Health Care Benefit Trust*

The postretirement health care benefit fund was established to provide for the payment of the Department's postretirement health care benefits. The adoption of GASB No. 45 had no impact on the amount or fair value of the trust (see note 12).

iii. *Nuclear Decommissioning Trust Funds*

Nuclear decommissioning trust funds will be used to pay the Department's share of decommissioning the Palo Verde Nuclear Generating Station at the end of its useful life (see note 1).

iv. *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.

v. *SCPPA Palo Verde Investment*

The SCPPA Palo Verde investment is a fixed rate investment held by SCPPA to be drawn down over the next 12 years to pay for purchased power obligations arising from the Department's participation in the SCPPA Palo Verde project.

vi. *Other Investments*

Other investments consist of funds held by SCPPA on behalf of the Department. Certain of these investments are currently being used by the Department 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 SCPPA. However, there are no restrictions imposed on the Department regarding the use of these investments.

As of June 30, 2006, the Power System's securities lending, cash collateral, and restricted investments and their maturities are as follows (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 agencies	$ 462,387	4,149	24,032	145,872	206,038	82,296
Medium-term notes	190,489	11,634	19,744	107,470	51,641	—
Commercial paper	158,070	121,009	27,168	9,893	—	—
Negotiable CDs	94,889	—	62,688	32,201	—	—
Money market funds	9,105	9,105	—	—	—	—
Securities lending cash collateral repurchase agreements	73,509	73,509	—	—	—	—
SCPPA Palo Verde investment	40,400	40,400	—	—	—	—
	$ 1,028,849	259,806	133,632	295,436	257,679	82,296

As of June 30, 2005, the Power System's securities lending, cash collateral, and restricted investments and their maturities are as follows (in thousands):

Investment type	Fair value	Investment maturities: 1 to 30 days	31 to 60 days	61 to 365 days	366 days to 5 years	Over 5 years
U.S. Government agencies	$ 606,968	70,464	22,977	220,265	193,293	99,969
Medium-term notes	186,988	21,239	28,260	85,810	51,679	—
Commercial paper	158,683	126,315	16,273	16,095	—	—
Negotiable CDs	33,090	—	—	33,090	—	—
Money market funds	7,291	7,291	—	—	—	—
Securities lending cash collateral repurchase agreements	155,481	155,481	—	—	—	—
SCPPA Palo Verde investment	43,094	—	—	—	—	43,094
	$ 1,191,595	380,790	67,510	355,260	244,972	143,063

vii. *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, 270 days for commercial paper; 397 days for negotiable certificates of deposits; and 45 days for repurchase agreements purchased with cash collateral from securities lending agreements.

viii. *Credit Risk*

Under its investment policy and the State of California Government 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 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 Department's investment policy specifies that money market funds may be purchased as allowed under the State of California Government Code (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 nationally recognized statistical rating organizations (NRSRO) or 2) retained an investment advisor registered or exempt from registration with the Securities and Exchange Commission with not less than five years experience managing money market mutual funds with assets under management in excess of five hundred million dollars. As of June 30, 2006 and 2005, each of the money market funds in the portfolio have attained the highest possible ratings by three NRSROs, specifically AAAm by Standard and Poor's Corporation (S&P), Aaa by Moody's Investors Services (Moody's), and AAA by Fitch Ratings (Fitch).

The U.S. Government agency securities in the portfolio consist of securities issued by government-sponsored enterprises, which are not explicitly guaranteed by the U.S.

Government. As of June 30, 2006 and 2005, the U.S. Government agency securities in the portfolio carried the highest possible credit ratings by the NRSROs that rated them.

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 Department's investments in corporate notes as of June 30, 2006, $3,385,560 (2.0%) was rated in the category of AAA, $129,933,595 (68.0%) was rated in the category of AA, and $57,170,056 (30.0%) was rated in the category of A by at least one NRSRO. Of the Power System's investments in corporate notes as of June 30, 2005, $15,337,713 (8.0%) was rated in the category of AAA, $81,553,979 (44.0%) was rated in the category of AA, and $90,095,668 (48.0%) was rated in the category of A by at least one NRSRO.

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, 2006 and 2005, 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. As of June 30, 2006 and 2005, all of the Power System's' investments in negotiable certificates of deposits were of the highest ranking by three NRSROs.

The Department's securities lending cash collateral investment policy specifies that repurchase agreement transactions shall be limited to broker-dealers or banks for which a securities lending line has been approved by the securities lending agent. Approved counterparties must be primary dealers in U.S. Government securities that work directly with the Federal Reserve Bank of New York. Repurchase agreements must be adequately collateralized based on the margin requirements for the type of security listed in the investment policy. As of June 30, 2006, the Power System did not have any securities on loan under securities lending transactions and therefore had no related reinvestments in repurchase agreements. As of June 30, 2005, the counterparties to the repurchase agreements were approved primary dealers that were rated with the highest short-term letter and number ratings as provided by two NRSROs. The collateral for the repurchase agreements consisted of mortgage-backed securities issued by U.S. Government agencies that had minimum credit ratings of AAA with a margin of 102.0% of the repurchase agreements.

ix. *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 30.0% 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, 2006, $148,351,195 (16.0%) was invested in securities issued by the Federal Home Loan Bank; $144,048,527 (16.0%) was invested in securities issued by the Federal Home Loan Mortgage Corporation; and

$129,360,590 (14.0%) was invested in securities issued by the Federal National Mortgage Association;

Of the Power System's total investments as of June 30, 2005, $198,249,683 (17.0%) was invested in securities issued by the Federal Home Loan Bank; $188,329,998 (16.0%) was invested in securities issued by the Federal National Mortgage Association; $168,174,337 (15.0%) was invested in securities issued by the Federal Home Loan Mortgage Corporation; and $52,214,278 (5.0%) was invested in securities issued by the Farm Credit Bank.

For overnight or open repurchase agreements, the Department's securities lending policy does not limit the percentage of cash collateral that may be invested with one particular counterparty.

Of the Power System's total investments as of June 30, 2005, all cash collateral received from securities lending transactions of $155,481,114 (14.0%) was invested in open repurchase agreements with Goldman Sachs & Co.

(b) Pooled Investments

The Power System cash, cash equivalents, and its collateral value of the City's securities lending program are included within the City Treasury's General and Special Investment Pool. As of June 30, 2006 and 2005, the Power System's share of the City's General and Special Investment Pool was $1,120,012,000 and $588,246,000, which represents approximately 15.0% and 9.0% of the Pool, respectively.

At June 30, 2006, 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**
U.S. Treasury notes	$ 750,633	—	—	—	750,633
U.S. Treasury bills	7,193	7,193	—	—	—
U.S. Government agencies	3,483,994	229,854	259,964	519,398	2,474,778
Medium term notes	1,077,004	—	—	125,689	951,315
Commercial paper	1,298,356	1,173,459	52,464	72,433	—
State of California LAIF	2,204	2,204	—	—	—
Short-term investment funds	13	13	—	—	—
Securities lending cash collateral:					
U.S. Treasury notes	607,597	—	—	—	607,597
U.S. Government agencies	344,340	—	—	—	344,340
Total general and special pools	$ 7,571,334	1,412,723	312,428	717,520	5,128,663

(Continued)

At June 30, 2005, 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
U.S. Treasury notes	$ 526,446	—	25,102	50,690	450,654
U.S. Government agencies	3,446,885	244,830	113,766	373,801	2,714,488
Medium-term notes	878,328	5,004	24,974	121,815	726,535
Commercial paper	861,293	844,318	16,500	475	—
State of California LAIF	40,703	40,703	—	—	—
Short-term investment funds	9	9	—	—	—
Securities lending cash collateral:					
U.S. Treasury notes	478,756	—	26,219	52,812	399,725
U.S. Government agencies	395,396	—	—	—	395,396
Total general and special pools	$ 6,627,816	1,134,864	206,561	599,593	4,686,798

i. *Interest Rate Risk*

The City's investment policy limits the maturity of its investments to a maximum of five years for U.S. Treasury and federal agency securities, medium-term corporate notes, and bonds issued by local agencies; 270 days for commercial paper; and 32 days for repurchase agreements.

ii. *Credit Risk*

The City's investment policy requires that for all classes of investments, except linked banking certificates of deposits, the issuers must have minimum credit ratings as follows: S&P A-1/A; Moody's P-1/A2; Fitch if available, F1/A. The City's investments in medium-term notes were rated A+ or better by S&P and A1 or better by Moody's, while investments in commercial paper were rated A-1+ by S&P, and P-1 by Moody's. As further required by the City's investment policy, corporations operating within the United States that have total assets in excess of $500 million issued the medium-term notes, and the commercial paper issuers are corporations organized in the United States as special purpose corporations, trust, or limited liability companies having program-wide credit enhancements. The State of California Local Agency Investment Fund is not rated.

iii. *Concentration of Credit Risk*

The City's investment policy does not allow more than 10.0% of its investment portfolio, except U.S. Treasury and federal agencies, to be invested in securities of a single issuer, including its related entities. The City's investment policy further provides for a maximum concentration limit of 30.0% on any individual federal agency or government-sponsored entity. The City's pooled investments comply with these requirements. GAAP requires

(Continued)

disclosure of certain investments in any one issuer that represent 5.0% or more of total investments; the City does not have such investments.

(8) Securities Lending Transactions

The Power System participates in two securities lending programs as follows (collateral amounts in thousands):

Program		Balance as of June 30, 2006	2005
Department Program	$	—	155,481
City of Los Angeles Program		73,509	37,318
	$	73,509	192,799

In December 1999, the Department initiated a securities lending program managed by its custodial bank to increase interest income. The bank lends up to 20.0% of the investments held in the debt reduction trust funds, decommissioning trust funds, postretirement health care benefits trust for securities, cash collateral or letters of credit equal to 102.0% of the market value of the loaned securities and interest, if any. The Department can sell securities received as collateral only in the event of borrower default. Both the investments purchased with the cash collateral received and the related liability to repay the cash collateral are reported on the balance sheets. A summary of the Power System's portion of the Department's securities lending program as of June 30, 2006 and 2005 is as follows (amounts in thousands):

Securities lent for cash collateral		2006 Fair value of underlying securities	2006 Collateral value	2005 Fair value of underlying securities	2005 Collateral value
U.S. Government and agency securities	$	—	—	152,315	155,481

Cash collateral received is reinvested by the lending agent in open repurchase agreements. As such, the maturities of reinvested cash collateral always match the maturities of the underlying securities lent. The lending agent provides indemnification for borrower default. There were no borrower or lending agent default losses during fiscal years 2006 and 2005.

General Investment Pool Program

The Power System also participates in the City's securities lending program through the pooled investment fund. The City's program has substantially the same terms as the Department's direct securities lending program. The Department recognizes its proportionate share of the cash collateral received for securities loaned and the related obligation for the general investment pool. As of June 30, 2006 and 2005, the Power

System's attributed share of cash collateral and the related obligation from the City's program was $73.5 million and $37.3 million, respectively.

Management believes that participation in these securities lending programs increases interest earnings and results in minimal credit risk exposure to the Department because the amounts owed to the borrowers exceed the amounts that have been loaned.

(9) Derivative Instruments

As a result of the Department's change in election under GASB No. 20 (see note 2), the Power System no longer records its derivative instruments at fair value on the balance sheets, but instead discloses the derivatives in the financial statement footnotes and records the impact upon settlement of the derivatives. The Power System had three main types of derivative instruments as of June 30, 2006 and 2005: electricity swaps, financial natural gas hedges, and gas forward contracts. As of June 30, 2006 and 2005, the fair values of these outstanding derivative instruments were $85.9 million and $104.3 million, respectively.

(a) Objective of Electricity Swap and Options

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.

A call option is the right, but not the obligation, to buy energy at a fixed price on or before a specific date. Because the Department has excess electric generation available at certain times during the year, it sells call options for a premium to other utilities. If the buyer calls the option, the Department is obligated to sell the energy for a specified dollar amount and deliver it to a specific delivery point. If the buyer does not call the option, the Department has no obligation to deliver energy, but does retain the premium paid. Premiums received are deferred and amortized to income over the period the option is outstanding and are recorded as part of sales for resale revenue. As of June 30, 2006 and 2005, the Power System had no deferred option revenue relating to options entered into prior to the fiscal year end.

The Department does not enter into gas and option agreements for trading purposes. The Department is exposed to risk of nonperformance if the counterparties default or if the swap agreements are terminated.

(b) Objective of 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.

(c) *Objective of Gas Forward Contracts*

The Department enters into gas forward contracts in order to supply its gas requirements to produce electricity to serve its customers.

As of June 30, 2006, the Power System had the following derivatives, which were not recorded on its balance sheet:

Derivative description	Total contract quantities	Contract price range $ per unit	First effective date	Last termination date	Fair value ($000's)	Cash received at derivative inception ($000's)
Electricity swaps:						
Purchases	121,600 MWs	63.00	10/1/06	12/31/06	(52,507)	—
Sales	121,600 MWs	66.50	10/1/06	12/31/06	478,107	—
Electricity options	30,800 MWs	75.50	7/1/06	9/30/06	(54,993)	345,884
Financial Natural Gas:						
Hedges*	91,336,000 MMBtu	4.30 – 7.49	10/1/05	6/1/10	85,521	—

* Financial hedges were variable to fixed rate swaps that serve to lock in a fixed cost of natural gas.

As of June 30, 2005, the Power System had the following derivatives, which were not recorded at fair value on its balance sheet:

Derivative description	Total contract quantities	Contract price range $ per unit	First effective date	Last termination date	Fair value ($000's)	Cash received at derivative inception ($000's)
Electricity swaps:						
Purchases	6,150 MWs	68.02	7/1/05	9/30/05	(1)	—
Sales	6,150 MWs	73.48	7/1/05	9/30/05	(10)	—
Gas contract*	11,132,490 MMBtu	5.93 – 7.82	3/15/91	3/15/06	(1,130)	—
Financial Natural Gas:						
Hedges**	95,466,500 MMBtu	4.05 – 7.39	7/1/05	6/30/09	105,443	—

* The gas contract allows for volumetric optionality. The quantity included in this table is based on forecasted draws from this contract which follow a seasonal pattern. Contract prices are based in part on Gas Price Indices, including Henry Hub and Kern River Prices.

** Financial hedges were variable to fixed rate swaps that serve to lock in a fixed cost of natural gas.

(d) *Fair Value*

All fair values were estimated using forward market prices available from broker quotes or exchange prices in the case of the gas contract.

(e) 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 (the Policy). The Policy includes provisions to limit risk including: the assignment of internal credit ratings to all Department counterparties based on counterparty and/or debt ratings; the requirement for credit enhancements (including 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, 2006, the eight financial natural gas hedge counterparties were rated by Moody's as follows: three at Aa1, two at Aa2, and three at Aa3. The counterparties were rated by S&P as follows: two at AA+, one at AA, two at AA-, and three at A+.

As discussed in note 3, during fiscal year 2001, the Power System experienced nonperformance and material counterparty default with the CISO and the CPX. The Power System does not anticipate nonperformance by any other of its counterparties and has no reserves related to nonperformance at June 30, 2006 and 2005. Apart from the events discussed in note 3, the Power System did not experience any material counterparty default during fiscal years 2006, 2005, or 2004.

(f) 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.

(10) Long-Term Debt

Long-term debt outstanding as of June 30, 2006 and 2005 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 2006	Principal outstanding 2005
Issue of 2001, Series A1	03/20/01	4.931%	2025	$	1,023,800	1,060,475
Issue of 2001, Series A2	11/06/01	5.109	2022		109,095	109,095
Issue of 2001, Series A3	04/01/01	5.095	2025		—	116,295
Issue of 2001, Series B	06/05/01	Variable	2035		620,600	620,600
Issue of 2001, Series C1	11/15/01	4.788	2017		4,543	4,582
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		11,846	13,537
Issue of 2003, Series A1	07/31/03	3.409	2017		422,380	440,110
Issue of 2003, Series A2	08/19/03	4.662	2032		515,830	515,830
Issue of 2003, Series B	08/28/03	5.013	2036		200,000	200,000
Issue of 2004, Series C3	04/07/04	4.298	2020		12,192	12,362
Issue of 2005, Series A1	12/28/05	4.700	2041		616,895	—
Issue of 2005, Series A2	12/28/05	4.700	2031		315,195	—
Issue of 2006, Series C4	03/01/06	4.040	2017		8,618	—
	Total principal amount				4,249,494	3,481,386
	Revenue Certificates				200,000	200,000
	Unamortized debt-related costs (including net loss on refundings)				1,075	(23,803)
	Debt due within one year (including current portion of variable rate debt)				(188,821)	(176,871)
				$	4,261,748	3,480,712

Revenue bonds generally are callable ten years after issuance. The Department has agreed to certain covenants with respect to bonded indebtedness. Significant covenants include the requirement that the Power System's net income, as defined, will be sufficient to pay certain amounts of future annual bond interest, 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, 2006 and 2005 (amounts in thousands):

		Balance at June 30, 2005	Additions	Reductions	Balance at June 30, 2006	Current portion
Long-term debt:						
Bonds	$	3,457,583	966,155	(173,169)	4,250,569	168,821
Revenue Certificates		200,000	—	—	200,000	20,000
Total	$	3,657,583	966,155	(173,169)	4,450,569	188,821

		Balance at June 30, 2004	Additions	Reductions	Balance at June 30, 2005	Current portion
Long-term debt:						
Bonds	$	3,503,386	567	(46,370)	3,457,583	156,871
Revenue Certificates		—	200,000	—	200,000	20,000
Total	$	3,503,386	200,567	(46,370)	3,657,583	176,871

(b) ***New Issuances***

Fiscal Year 2006

In December 2005, the Power System issued $932 million of Power System Revenue Certificates. Also, in March 2006, the Power System issued $8.9 million of Mini-Bonds. The net proceeds from both transactions were deposited into the construction fund to be used for capital improvements

Fiscal Year 2005

In September 2004, the Power System issued $200 million of Power System Revenue Certificates. The net proceeds were deposited into the construction fund to be used for distribution system capital improvements.

Fiscal Year 2004

In July 2003, the Power System issued $956 million of Power System Revenue Bonds. The bonds were issued for the purpose of refunding portions of the Refunding Issue of 1993, the Second Issue of 1993, and the Issue of 2000. The net proceeds along with $60 million in cash were used to defease bonds with a par value of $1.025 billion. The defeasance is expected to reduce total debt payments over the life of the new issues by $186 million and is expected to result in present value savings of approximately $71 million. This transaction resulted in a net loss for accounting purposes of $57 million, of which $53.5 million was deferred and is being amortized over the shorter of the life of the bonds retired or the life of the new bonds, and $3.5 million was recognized in fiscal year 2004 as part of debt expenses.

In August 2003, the Power System issued $200 million of Power System Revenue Bonds. The net proceeds were deposited into the construction fund to be used for distribution system capital improvements. Also, in April 2004, the Power System issued $10 million of Power System fixed rate bonds as part of the Mini-Bond Program for employees and retirees. The net proceeds were deposited into the construction fund to be used for distribution system capital improvements.

(c) Outstanding Debt Defeased

The Power System defeased certain revenue bonds in 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.

In July 2005, the Power System defeased the $116.3 million Power System Revenue Bonds, Series A, Sub-series A-3, with a carrying amount of $115.3 million, by utilizing $110.7 million from the debt reduction trust fund to purchase securities placed in an irrevocable trust to provide for all future debt service on the bonds. The transaction resulted in a realized gain of $4.6 million that was netted against interest on debt.

At June 30, 2006, the following revenue bonds outstanding are considered defeased and remained outstanding (amounts in thousands):

Bond issues		Principal outstanding
Third Issue of 1991	$	350
Issue of 1992		990
Second Issue of 1993		9,085
Refunding Issue of 1994		46,165
Issue of 1994		6,105
Issue 2001, Series A3		116,295
	$	178,990

(d) Variable Rate Bonds and Revenue Certificates

The variable rate bonds currently bear interest at daily and weekly rates (ranging from 3.95% to 5.31% as of June 30, 2006). 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 revenue certificates bear interest at an average rate of 3.49%. The Power System has entered into standby and line of credit agreements with a syndicate of commercial banks in an initial amount of $620.6 million, $388.5 million, and $200 million to provide liquidity for the variable rate bonds and revenue certificates. The extended standby agreements expire on February 8, 2007 for the $620.6 million issue and on July 11, 2008 for the $388.5 million issue. The $200 million line of credit agreement for the revenue certificates expires on September 15, 2007.

Bonds purchased under the agreements will bear interest that is payable quarterly at the greater of the Federal Funds Rate plus 0.50% or the bank's announced base rate, as defined. The unpaid principal of bonds purchased is payable in ten-equal semiannual installments, commencing after the termination of the agreement. 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. These bonds have been classified as long term on the balance sheets 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. That portion which 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 have been included in the current portion of long-term debt and was $120.9 million at June 30, 2006 and 2005.

(e) ***Scheduled Principal Maturities and Interest***

Scheduled annual principal maturities and interest are as follows (amounts in thousands):

		Principal	Interest and amortization
Fiscal years ending June 30:			
2007	$	67,911	194,951
2008		41,826	193,378
2009		58,525	191,257
2010		98,952	187,274
2011		120,345	181,846
2012-2016		680,632	811,303
2017-2021		561,202	668,183
2022-2026		792,906	479,359
2027-2031		822,430	293,432
2032-2036		894,105	100,076
2037-2041		110,660	9,273
Total requirements	$	4,249,494	3,310,332

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 $1,209.1 million in variable rate bonds outstanding over the next six years, as follows: $120.9 million in fiscal year 2007, $241.8 million in each of the fiscal years 2008 through 2011, and $121.0 million in fiscal year 2012. Accordingly, the balance sheets include the possibility of the exercise of the tender options and reflect the $120.9 million that could be due in fiscal year 2007 as a current portion of long-term debt payable. Interest and amortization includes interest requirements for variable rate bonds, using the variable debt interest rate in effect at June 30, 2006 of 3.95% for tax-exempt bonds and 5.31% for taxable bonds.

(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 6.0% 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. The Department contributes $1.10 for each $1.00 contributed by participants plus an actuarially determined annual required contribution as determined by the Plan's independent actuary. 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 of Los Angeles 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, CA 90012.

The annual pension cost (APC) and net pension obligation (NPO) for the Department's plan consists of the following (amounts in thousands):

		Year ended June 30,	
		2006	2005
Annual required contribution	$	118,342	79,201
Interest on net pension asset		(13,023)	(13,938)
Adjustment to annual required contribution		19,405	20,764
APC (including $36.2 million and $24.4 million of amounts capitalized in fiscal 2006 and 2005, respectively)		124,724	86,027
Department contributions		(101,630)	(75,501)
Change in NPO		23,094	10,526
NPO (asset) – beginning of year		(171,658)	(182,184)
NPO (asset) – end of year	$	(148,564)	(171,658)

The Power System's allocated share of APC and NPO consists of the following (amounts in thousands):

		Year ended June 30,	
		2006	2005
Annual required contribution	$	78,106	52,272
Interest on net pension asset		(8,595)	(9,199)
Adjustment to annual required contribution		12,807	13,704
APC (including $21.6 million and $13.9 million of amounts capitalized in fiscal 2006 and 2005, respectively)		82,318	56,777
Department contributions		(67,590)	(49,027)
Change in NPO		14,728	7,750
NPO (asset) – beginning of year		(114,521)	(122,271)
NPO (asset) – end of year	$	(99,793)	(114,521)

Annual required contributions are determined through actuarial valuations using the entry age normal 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 the period ended June 30, 2004. As a result of an April 2000 amendment to the Plan, the amortization period was changed to rolling 15-year periods effective July 1, 2000.

In accordance with actuarial valuations, the Department's required contribution rates are as follows:

Actuarial valuation date July 1	Normal cost	Surplus amortization	Contribution rate
2005	10.77%	7.69%	19.20%
2004	10.83	2.10	13.45
2003	10.89	(2.76)	8.45

The significant actuarial assumptions include an investment rate of return of 8.0%, projected inflation-adjusted salary increases of 5.5%, and postretirement benefit increases of 3.0%. The actuarial value of assets is determined using techniques that smooth the effects of short-term volatility in the market value of investments over a four-year period. Plan assets consist primarily of corporate and government bonds, common stocks, mortgage-backed securities, and short-term investments.

(Continued)

Trend information for fiscal years 2006, 2005, and 2004 for the Power System is as follows (amounts in thousands):

Year ended June 30	NPO (asset)	Percentage of APC contributed	APC
2006	$ (99,793)	82.0%	$ 82,318
2005	(114,521)	86.0	56,777
2004	(122,271)	109.0	33,831

Disability and Death Benefits

The Power System's allocated share of disability and death benefit plan costs and administrative expenses totaled $9 million, $9 million, and $8 million for each of the fiscal years 2006, 2005, and 2004, respectively.

(12) Postretirement Health Care Plan

(a) Plan Description

The Department provides certain health care benefits to active and retired employees and their dependents. The health care 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 Boards. The total number of active and retired Department participants entitled to receive benefits was approximately 16,750 and 16,450 at June 30, 2006 and 2005, respectively.

The health plan is a single-employer defined benefit plan that is not administered as a trust or equivalent arrangement and, therefore, does not have separate financial statements.

(b) Funding Policy

The Department pays a monthly maximum subsidy of $2,429 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 are required to pay the difference. No funding policy has been established for the future benefits to be provided under this plan. However, in fiscal years 2006 and 2005, the Department increased the postretirement trust assets by $100 million (Power System's portion, $66 million) in addition to the $53 million it paid for current retiree premiums (Power System's portion, $34.6 million). These trust assets are irrevocably committed to funding participant benefits.

(c) Annual OPEB Cost and Net OPEB Obligation

The annual other postretirement benefit (OPEB) cost (expense) is calculated based on the annual required contribution of the employer (ARC), an amount actuarially determined in accordance with

(Continued)

the parameters of GASB No. 45. 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 other postretirement benefit obligation (amounts in thousands):

		Year ended June 30,	
		2006	2005
Annual required contribution	$	110,813	99,684
Interest on net OPEB obligation		7,094	4,030
Adjustment to annual required contribution		(5,353)	(510)
		112,554	103,204
Contributions made		(52,990)	(52,544)
Change in net other postretirement benefit obligation		59,564	50,660
Net other postretirement benefit obligation – beginning of year		109,140	58,480
Net other postretirement benefit obligation – end of year	$	168,704	109,140

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 other postretirement obligation (amounts in thousands):

		Year ended June 30,	
		2006	2005
Annual required contribution	$	73,137	64,795
Interest on net OPEB obligation		4,682	2,620
Adjustment to annual required contribution		(3,533)	(332)
		74,286	67,083
Contributions made		(34,631)	(34,402)
Change in net other postretirement benefit obligation		39,655	32,681
Net other postretirement benefit obligation – beginning of year		71,168	38,487
Net other postretirement benefit obligation – end of year	$	110,823	71,168

(Continued)

The reconciliation of the postretirement trust assets as of June 30, 2006, representing the set aside assets in the irrevocable employer trust, is as follows (dollar amount in thousands):

		Department	Power System's share
Postretirement trust assets – beginning of year	$	396,361	271,082
Contributions to trust		107,650	71,237
Postretirement trust assets – end of year	$	504,011	342,319

The Department's annual OPEB costs, the percentage of annual required contribution contributed to the Plan, and the net postretirement obligation for fiscal years 2006 and 2005, were as follows (amounts in thousands):

		2006	2005
Annual OPEB cost	$	112,554	103,204
Percentage of the ARC contributed		47.0%	51.0%
Net postretirement obligation	$	168,704	109,140

The Power System's share in the annual OPEB cost, the percentage of annual required contribution contributed to the Plan, and the net postretirement obligation for fiscal years 2006 and 2005, were as follows (amounts in thousands):

		2006	2005
Annual OPEB cost	$	74,285	67,083
Percentage of the ARC contributed		47.0%	51.0%
Net postretirement obligation	$	110,823	71,168

(d) *Funded Status and Funding Progress (Unaudited)*

As of July 1, 2005, the Department's actuarial accrued liability for benefits was $1.7 billion resulting in an unfunded actuarial accrued liability (UAAL) of $1.7 billion. The covered payroll (annual payroll of active employees covered by the Plan) was $612.3 million, and the ratio of the UAAL to the covered payroll was 277.0%.

As of July 1, 2004, the Department's actuarial accrued liability for benefits was $1.6 billion resulting in an UAAL of $1.6 billion. The covered payroll (annual payroll of active employees covered by the Plan) was $629 million, and the ratio of the UAAL to the covered payroll was 297.0%.

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 health care cost trend. Amounts determined regarding the funded status of the Plan and the annual required contributions 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 actuarial accrued liabilities 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 actuarial accrued liabilities and the actuarial value of assets, consistent with the long-term perspective of the calculations.

In the July 1, 2005 actuarial valuation, the entry age normal cost method was used. The actuarial assumptions include 6.5% discount rate, which represents the expected long-term return on plan assets, an annual health care cost trend rate of 11.0% initially, reduced by decrements to an ultimate rate of 5.0% after six years. Both rates include a 4.0% 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 30-year period.

In the July 1, 2004 actuarial valuation, the entry age normal cost method was used. The actuarial assumptions include 6.5% discount rate, which represents the expected long-term return on plan assets, an annual health care cost trend rate of 12.0% initially, reduced by decrements to an ultimate rate of 5.0% after seven years. Both rates include a 3.5% 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 30-year period.

(f) New Legislation

In December 2003, the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 was enacted, effective in 2006. Two important aspects of the law may affect the employer's financial statements before 2006. First, the opportunity for retirees to obtain prescription drug benefits under new Medicare Part D will tend to shift benefits and related costs out of employer plans. Second, employers that provide prescription drug benefits that are at least as valuable as (actuarially equivalent) those under Medicare Part D will be entitled to annual subsidy from Medicare equal to 28.0% of prescription drug costs between $250 and $5,000 for each Medicare-eligible retiree who does not join Part D.

(13) Other Long-Term Liabilities

(a) *Other Long-Term Liabilities*

The Power System had the following other long-term liabilities:

		Balance at June 30, 2005	Additions	Reductions	Balance at June 30, 2006
Deferred credits:					
Purchased power	$	612,828	—	(78,556)	534,272
Public benefits		12,727	12,601	—	25,328
Other		—	4,564	—	4,564
	$	625,555	17,165	(78,556)	564,164
Accrued workers' compensation claims	$	35,558	10,934	(10,934)	35,558

		Balance at June 30, 2004	Additions	Reductions	Balance at June 30, 2005
Deferred credits:					
Purchased power	$	540,150	72,678	—	612,828
Public benefits		—	12,727	—	12,727
	$	540,150	85,405	—	625,555
Accrued workers' compensation claims	$	31,352	8,415	(4,209)	35,558

(b) *Deferred Credits*

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 year 2006, the Power System reversed $78.5 million related to precollected purchase power costs. At June 30, 2006 and 2005, $534.3 million and $612.8 million, respectively, remain as part of deferred credits related to precollected purchased power costs.

(c) *Public Benefits*

The Department defers public benefits revenue from customers in excess of costs incurred under qualifying programs and defers qualifying expenses in excess of collections pursuant to approval received from the Board. As of June 30, 2006 and 2005, the Department has recorded a deferred credit in the amount of $25.3 million and $12.7 million, respectively, due to public benefit expenses below revenues.

(Continued)

(d) *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 3.0% at June 30, 2006. The Department has third-party insurance coverage for workers' compensation claims over $1 million.

Overall indicated reserves for workers' compensation claims, for both the Water System and the Power System, undiscounted, have decreased from $63.8 million as of June 30, 2005 to $61.2 million as of June 30, 2006. This decrease is mainly attributable to favorable development stems for prior fiscal years due to changes in reserving practices. In addition a number of legislative reforms impacting workers compensation costs were passed in 2002, 2003, and 2004. The reforms increase statutory benefits and put in place controls for medical utilization. Industry estimates of the impact of the reforms on medical costs are a decrease of 36.0%.

Changes in the Department's liability since June 30, 2004 are summarized as follows (amounts in thousands):

		June 30,	
	2006	2005	2004
Balance at beginning of year	$ 63,785	55,990	45,535
Current year claims and changes in estimates	12,646	15,166	16,715
Payments applied	(15,258)	(7,371)	(6,260)
Balance at end of year	$ 61,173	63,785	55,990

The Power System's portion of the discounted reserves is $35.6 million as of June 30, 2006 and 2005.

(14) Loss on Asset Impairment and Abandoned Project

During fiscal year 2006, the Mohave Generating Station (Mohave) was shut down due to the lack of remediation efforts to comply with environmental, water, and coal issues. This closure was anticipated in 2004, and as such the Department recorded a loss on Mohave totaling $8.1 million. The loss was recorded using the service units approach under GASB No 42, *Accounting and Financial Reporting for Impairment of Capital Assets and for Insurance Recoveries*. During fiscal year 2004, the Department discontinued using a procurement system. The Power System's portion of the loss related to this system totaled $5.5 million.

(15) 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 fund net assets 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 fund net assets.

The Department authorized total transfers of $157.9 million, $160.2 million, and $210.2 million in fiscal years 2006, 2005, and 2004, respectively, from the Power System to the reserve fund of the City. Included in these amounts was a transfer of $60.0 million, which was accrued as liabilities as of June 30, 2004. The $60.0 million accrued as of June 30, 2004 was paid in fiscal year 2005.

(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 (the DOE) is to develop facilities necessary for the storage and disposal of spent fuel and have the first such facility in operation by 1998; however, the DOE has announced that such a repository cannot be completed before 2010. There is ongoing litigation with respect to the DOE's ability to accept spent nuclear fuel; however, no permanent resolution has been reached.

Capacity in existing fuel storage pools at PVNGS was exhausted in 2003. A Dry Cask Storage Facility (also called the Independent Spent Fuel Storage Facility) was built and completed in 2003 at a total cost of $33.9 million (about $3.3 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 2026. The Department accrues for current nuclear fuel storage costs as a component of fuel expense as the fuel is burned. The Department's share of spent nuclear fuel costs related to its indirect interest in PVNGS is included in purchased power expense.

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 $300 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 $100.6 million for each licensee for each nuclear incident occurring at any nuclear reactor in the United States; payments under the program are limited to $10 million per incident, per year. Based on the Department's 5.7% direct interest and its 3.95% indirect investment interest through SCPPA, the Department would be responsible for a maximum assessment of $9 million per incident, limited to payments of $1 million per incident annually.

(c) *Environmental Matters*

Numerous environmental laws and regulations affect the Power System's facilities and operations. The Department monitors its compliance with environmental 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.

In May 2001, SCAQMD adopted amendments to RECLAIM with the intent of lowering and stabilizing RTC prices. One key element of the amendments is that existing power plants were bifurcated from the rest of the RECLAIM market and were required to install Best Available Retrofit Control Technology (BARCT). As required under SCAQMD rules, the Department met the BARCT compliance date of January 1, 2003. In January 1, 2007, power producers can reenter the RECLAIM market. 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 until 2010.

Air Quality – Greenhouse Gas Emissions

In September 2006, Governor Schwarznegger signed the California Global Warming Solutions Act of 2006 (AB32) and Senate Bill 1368, Electricity: Emissions of Greenhouse Gases (SB1368). AB32 requires the California Air Resources Board to develop regulations and market mechanisms that will ultimately reduce California's greenhouse gas emissions by 25.0% by 2020. Mandatory caps will begin in 2012 for significant sources and be gradually reduced to meet the 2020 goals. As specified in AB32, all emissions from electricity that are consumed in the state, whether it is generated in California or in other states, will be subject to the cap. As a result, the Power System's share of emissions from IPP and other facilities outside California will be subject to this program. SB1368 will require local publicly owned electric utilities to comply with a greenhouse gas emission performance standard prior to entering into a long-term financial commitment for baseload generation. As defined in SB1368, "long-term financial commitment means either a new ownership investment in baseload generation or a new or renewed contract with a term of five or more years, which includes procurement of baseload generation." Baseload generation refers to power plants with an annualized capacity factor of at least 60.0%.

It is uncertain at this time what impact these statutes will have on the Power System's operations. If a cap and trade program is established under AB32, the primary issue will be how allowances will be allocated to the Department and other power producers. The target date for the Air Resources Board to adopt regulations is January 1, 2011. The goal of the AB32 regulations would be to "achieve the maximum technologically feasible and cost-effective reductions in greenhouse gas, including provisions for using both market mechanisms and alternative compliance mechanisms." As required under SB1368, the California Energy Commission will adopt regulations to implement a greenhouse gas emission performance standard for local publicly owned utilities by June 30, 2007. Once adopted, the Department will be required to meet the emission performance standard for new contracts and major investments at its existing facilities. The Department will be actively participating in the rulemaking process for both AB32 and SB1368

Power Plant Once-Through Cooling Water Systems

Once-through cooling 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 once-through cooling 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.

Regulatory agencies have made several changes recently that could significantly impact operations at the Haynes, Scattergood, and Harbor Generating Stations. The Environmental Protection Agency has adopted new regulations that would affect the water that is drawn into these plants for cooling purposes, and for the Haynes and Harbor stations, the Regional Water Quality Control Board reclassified the body of water that the once-through cooling water is discharged to. For Haynes, this reclassification includes requirements that cannot currently be met with its existing cooling 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.

(d) ***Litigation***

The state and a number of local government agencies that are electric customers of the Department claim that the Department has violated the state's False Claim Act by charging such governmental customers the standard rates applicable to both public and private customers in their respective customer rate categories. The plaintiffs allege that such rates include a capital facilities charge in violation of the state's statute. The plaintiffs are seeking unspecified amounts for treble damages, civil penalties, and injunctive relief. The Department intends to vigorously defend the claim.

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, 2006 and 2005.

(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, 2006 and 2005.

(f) Credit Risk

Financial instruments, which potentially expose the Department to concentrations of credit risk, consist primarily of retail and wholesale receivables. The Department's retail customer base is concentrated among commercial, industrial, residential, and governmental customers located within the City. Although the Department is directly affected by the City's economy, management does not believe significant credit risk exists at June 30, 2006 and 2005, except as provided in the allowance for losses. The Department manages its credit exposure by requiring credit enhancements from certain customers and through procedures designed to identify and monitor credit risk.

(16) Subsequent Event

On September 19, 2006, the Board approved the creation of a Retiree Health Benefits Fund to be maintained by the Retirement Plan Office. During fiscal year 2007, the assets held by both the Water and the Power System are to be transferred to this newly created fund. This transfer will reduce the Power System's restricted investments and restricted fund net assets.

On August 16, 2006, the City Council approved the unfreezing of the energy cost adjustment factor. This change took effect October 1, 2006.

LOS ANGELES DEPARTMENT OF WATER AND POWER
POWER SYSTEM

Required Supplementary Information

June 30, 2006

(Unaudited)

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 (a)	Actuarial accrued liability (AAL) (b)	Unfunded AAL (UAAL) (b-a)	Funded ratio (a/b)		Covered payroll (c)	UAAL as a percentage of covered payroll (b-c/a)
2005	$	6,331,048	6,763,080	432,032	94.0%	$	616,270	70.0%
2004		6,251,421	6,421,814	170,393	97.0		581,039	29.0
2003		6,128,376	6,042,087	(86,289)	101.0		527,787	(16.0)

Postretirement Health Care 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 (a)	Actuarial accrued liability (AAL) (b)	Unfunded AAL (UAAL) (b-a)	Funded ratio (a/b)		Covered payroll (c)	UAAL as a percentage of covered payroll (b-c/a)
2005	$	—	1,695,666	1,695,666	—%	$	612,270	277.0%
2004		—	1,597,835	1,597,835	—		628,898	297.0
2003		—	1,729,706	1,729,706	—		571,726	303.0

See accompanying independent auditors' report.