El Paso Electric

Jeffrey T. Weikert
Assistant General Counsel

P.O. Box 982
El Paso, Texas
79960-0982
(915) 543-5711

November 5, 2008

Arizona Public Service Company
Attention Kelley Rasmussen
5801 S. Wintersburg Road
Mail Station 7636
Tonopah, Arizona 85354-7529

Re: Palo Verde Nuclear Generating Station
Secondary Financial Protection Licensee
Guaranteed Payment of Deferred Premium
NRC 10 C.F.R. § 140.21(e)

Dear Ms. Rasmussen:

Pursuant to our November 5, 2008 telephone conversation, enclosed is a sealed envelope containing copies of the following documents previously forwarded by Mr. Michaelis of your company to the Nuclear Regulatory Commission ("NRC"):

1. Cover letter to the NRC dated July 2, 2008, a copy of which is enclosed for your records;
2. El Paso Electric Company ("EPE") Form 10-K Annual Report for the year ended December 31, 2007;
3. EPE's certified 2008 Cash Flow Projection (the "Projection") marked "Confidential and Proprietary Commercial and Financial Information Submitted Under 10 U.S.C. § 2.390"; and
4. Application to the NRC pursuant to 10 C.F.R. § 2.390, including the Affidavit of Mr. Steven P. Busser, Vice President, Treasurer, and Chief Risk Officer of EPE, requesting that the Projection be withheld from public disclosure.

In accordance with our discussion, please submit the sealed envelope to the NRC. APS's submission of the sealed envelope to the NRC will help to maintain the confidentiality of the Projection and will assist the NRC's determination of the Application.

Your assistance with this matter is appreciated in advance. If you have any questions or comments concerning this matter, please let me know.

Sincerely,

Jeffrey T. Weikert

M001
1/1

(915) 543-5759 – Direct

100 N. Stanton Street
El Paso, Texas 79901

(915) 521-4747 – Facsimile

To: Nuclear Regulatory Commission

Re: Application regarding El Paso Electric Company 2008 Cash Flow Projection submitted pursuant to 10 C.F.R. Section 140.21(e).

Pursuant to 10 C.F.R. § 2.390, El Paso Electric Company hereby applies for withholding from public disclosure the following document:

"El Paso Electric Company 2008 Cash Flow Projection"

Affidavit:

I, Steven P. Busser, Vice President, Treasurer, and Chief Risk Officer of El Paso Electric Company, in my capacity as an officer of El Paso Electric Company, hereby represent, affirm, and request that the above-mentioned document, "El Paso Electric Company 2008 Cash Flow Projection" be withheld from public disclosure for the following reasons:

1. This information has not been released publicly;

2. This information is customarily held in confidence by El Paso Electric Company;

3. This information has been transmitted to the NRC, in a confidential manner;

4. This information cannot be constructed from any other source; and

5. Disclosure of this information may cause substantial harm to the El Paso Electric Company's competitive position and would give parties who have access to this information inside knowledge of El Paso Electric Company's projected operations that is not available to the general public.

Signed: _____
Steven P. Busser
Vice President, Treasurer,
and Chief Risk Officer
El Paso Electric Company

Subscribed and sworn to before me on this 2nd day of July, 2008.

_____
Notary Public

My commission expires:
3/24/11

CAROLINA PENA
MY COMMISSION EXPIRES
March 24, 2011

10 CFR 140.21(e)

APS

A subsidiary of Pinnacle West Capital Corporation

Palo Verde Nuclear Generating Station

Thomas N. Weber
Department Leader
Regulatory Affairs

Tel. 623-393-5764
Fax 623-393-5442

Mail Station 7636
PO Box 52034
Phoenix, Arizona 85072-2034

102-05873-TNW/KAR
July 25, 2008

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

Dear Sir:

Subject: Palo Verde Nuclear Generating Station (PVNGS)
Units 1, 2, and 3
Docket Nos. STN 50-528/529/530
Licensee Guarantee of Payment of Deferred Premium

Pursuant to the requirements of 10 CFR 140.21(e), Arizona Public Service Company (APS), for itself and on behalf of the PVNGS Participants, has enclosed projected cash flow statements for each participant, except Southern California Edison, who submitted their Statement to the NRC in a letter dated April 2, 2008.

Please note that the projected cash flow statement for the El Paso Electric Company is considered a confidential document, for which an affidavit is provided. The affidavit sets forth the basis on which the Commission may withhold the information from public disclosure. Accordingly, it is requested that the El Paso Electric Company projected cash flow statement be withheld from public disclosure.

No commitments are being made to the NRC in this letter. If you have any questions, please contact Rusty Stroud at (623) 393-5111.

Sincerely,

Thomas N. Weber

TNW/RAS/KAR/gat

Enclosure

cc: E. E. Collins Jr. (all w/o enclosure)
M. T. Markley
R. I. Treadway

NOOA
NRR

Enclosure

Cash Flow Statements for:

Arizona Public Service Company
Salt River Project
Public Service Company of New Mexico
Los Angles Department of Water & Power
Southern California Public Power Authority
El Paso Electric Company

INTERNAL CASHFLOW PROJECTION OF ARIZONA PUBLIC SERVICE COMPANY
(Joint Owner Of Palo Verde Nuclear Generating Station**)

($000)

		2008 *Estimate*
1.	Net Income After Taxes - Continuing Operations	(3)
	Less:	
2.	Dividends Paid on Preferred Stock	(3)
3.	Dividends Paid on Common Stock	(3)
4.	Retained Earnings	(3)
	Adjustments:	
5.	Depreciation and Amortization (1)	422,091
6.	Deferred income Taxes	(7,114)
7.	Allowance for Funds Used During	-
	Construction (Equity & Borrowed)	(38,792)
8.	Decommissioning	(19,210)
9.	Deferred Fuel	99,176
10.	Total Adjustments (4)	456,151
11.	Internal Cash Flow	(3)
12.	Average Quarterly Cash Flow	(3)

NOTES: ** Percentage Ownership in All Nuclear Units:
Unit 1 - 29.1%
Unit 2 - 29.1% (2)
Unit 3 - 29.1%

(1) Includes Nuclear Fuel Amortization
(2) Includes the leased portion of Palo Verde Unit 2.
(3) Company policy prohibits disclosure of financial forecast data which will enable earnings or dividend forecasts by unauthorized persons, unless assured of confidentiality
(4) Excludes forecasted changes in working capital.

I, Barbara M. Gomez, Vice President and Treasurer of APS, certify that these cashflow calculations utilize the Company's approach to estimating cash flows for internal management reports and planning purposes. The 2008 estimate of cashflows is based on the 2008 Company Budget. The 2008 estimate does not reflect actual results to date, as the Budget is not revised to reflect changing conditions.

Barbara M. Gomez

Barbara M. Gomez
Vice President and Treasurer of APS

INTERNAL CASH FLOW PROJECTION OF THE SALT RIVER PROJECT
(JOINT OWNER OF PALO VERDE NUCLEAR GENERATING STATION)
FOR FISCAL YEARS ENDED APRIL 30, 2008 AND 2007
($000)

	2008 ACTUAL	2007 ACTUAL
Net Income After Taxes	$ 257,103	$ 367,790
Less Dividends Paid:		
Preferred Dividend Requirements		
Dividends on common Stock		
Retained Earnings	257,103	367,790
Adjustments:		
Depreciation and Amortization	369,477	348,643
Deferred Income Taxes and Investment Tax Credits		
Allowance for Funds Used During Construction	(23,552)	(9,110)
Cumulative Effect of Change in Accounting Principle	-	-
Total Adjustments	345,925	339,533
Internal Cash Flow	603,028	707,323
Average Quarterly Cash Flow	$ 150,757	$ 176,831
Percentage Ownership in all Nuclear Units		
Unit 1	17.49%	17.49%
Unit 2	17.49%	17.49%
Unit 3	17.49%	17.49%

I, Sue Ann Perkinson, Manager of Corporate Accounting Services of the Salt River Agricultural Improvement and Power District certify that the above figures are based upon our accounting records, and agree, as appropriate with our audited financial statements.

Sue Ann Perkinson

Sue Ann Perkinson

2008 PRO FORMA CASH FLOW STATEMENT
FOR PUBLIC SERVICE COMPANY OF NEW MEXICO
(EXCLUDING NON-UTILITY SUBSIDIARIES)

(In Thousands)	2007 Actual	2008 Projected
Net Income After Taxes	38,907	(1)
Less Dividends Paid	(528)	(1)
Adoption of FIN 48	(1,132)	
Earnings Retained	37,247	(1)
Adjustments:		
Depreciation & Amortization	126,255	133,523
Deferred Income Taxes & ADITC	16,704	0
AFUDC	7,724	10,309
Other	(665)	(5,386)
Total Adjustments	150,018	138,446
INTERNAL CASH FLOW	188,924	(1)
Average Quarterly Cash Flow	47,231	(1)

(1) Financial Forecast data which will enable earnings or dividend forecasts by unauthorized persons is not provided.

Percentage Entitlement in all Nuclear Units:

Palo Verde Unit 1 --- 10.2%
Palo Verde Unit 2 --- 10.2%
Palo Verde Unit 3 --- 10.2%

EVP

I, Charles Eldred, ~~Senior Vice President~~ and Chief Financial Officer, PNM Resources, Inc., certify that these cash flow calculations utilize the Company's approach to estimating cash flows for internal management reports and planning purposes.

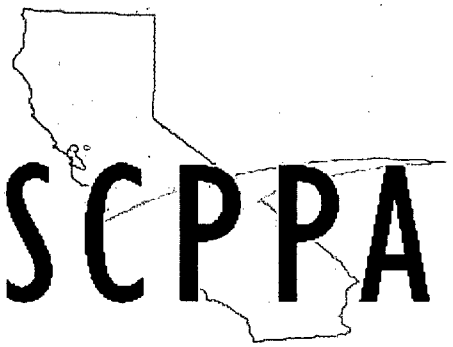
CEldred

6-25-2008

LOS ANGELES DEPARTMENT OF WATER & POWER
Power System
2008 Internal Cash Flow Projection
For Palo Verde Nuclear Power Station

in thousands	2006-07 Actual	2007-08 Projection*
Net Income Before City Transfer	331,064	289,828
Transfer to the City	(174,747)	(182,000)
	156,317	107,828
Adjustments:		
Depreciation & amortization	269,587	282,300
Loss on asset Impairment & Abandoned Projects	0	0
Allowance for funds used during construction	(10,773)	(13,588)
Total Adjustments	258,814	268,712
Internal Cash Flow	$ 415,131	$ 376,540

**Based on FS_PS_Jun 11_0809 Budget (Actuals through April 2008)*



Southern California Public Power Authority

Combined Financial Statements
March 31, 2008 and 2007

(Unaudited)

Southern California Public Power Authority
Combined Financial Statements (Unaudited)
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Management's Discussion and Analysis

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. The Authority applies all statements and interpretations issued by the Governmental Accounting Standards Board (GASB) that are 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 Regulatory Commission (FERC).

Prepaid Natural Gas Project

On October 11, 2007, the Authority issued $504 million of Gas Project Revenue Bonds, Project No. 1 (the Bonds) and made a one-time prepayment of $481 million to acquire the right to receive approximately 135 billion cubic feet of natural gas from J. Aron & Company over a 30-year term. In addition, $23 million of the proceeds funded certain accounts that were established to pay capitalized debt service and other administrative costs associated with the prepayment transaction until gas delivery begins in July 2008. In connection with the prepayment, SCPPA also entered into a commodity price swap arrangement with the gas supplier, thereby allowing the Project Participants to purchase gas at a discounted index price.

On October 3, 2007, prior to the acquisition of the prepaid gas supply, the Authority entered into five separate Prepaid Natural Gas Sales Agreements (the Gas Sales Agreements) with J. Aron and simultaneously, five Prepaid Natural Gas Supply Agreements (Project 1) (the Gas Supply Contracts) in which the Authority sold its interest in the natural gas, on a "take-and-pay" basis, to the cities of Anaheim, Burbank, Colton, Glendale, and Pasadena (the Project Participants). In exchange for the one-time prepayment, beginning July 1, 2008, J. Aron has contracted to deliver gas to the Authority, in specified daily quantities each month, at designated delivery points on the natural gas pipelines, in accordance with the terms of each of the Gas Sales Agreements. Through the Gas Supply Contracts, SCPPA has provided for the sale to the Project Participants, on a pay-as-you-go basis, of all of the natural gas to be delivered to SCPPA pursuant to the Gas Sales Agreements. The Bonds are payable solely from the revenues derived under the terms of the Gas Supply Contracts.

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

PROJECT PARTICIPANT	AVERAGE DAILY QUANTITY (1)	PERCENTAGE BY PARTICIPANT
City of Anaheim	2,000	16.5%
City of Burbank	4,000	33.0%
City of Colton	1,375	11.0%
City of Glendale	2,750	23.0%
City of Pasadena	2,000	16.5%
TOTAL	12,125	100%

(1) The average Daily Quantity is calculated over the term of the applicable Gas Supply Contract

Long Term Debt

On February 6, 2008, SCPPA issued three separate Natural Gas Project A, 2008 Revenue Bonds, (Taxable): City of Anaheim, $80,795,000; City of Burbank, $43,700,000; and City of Colton, $16,565,000 for an aggregate principal total of $141,060,000. These fixed rate taxable bonds mature on 7/1/2032 and were issued to pay off the expiring bridge loan of $76,000,100 from Merrill Lynch, and to provide for capital drilling needs over the next five years for both the Wyoming and Texas Natural Gas Reserves Projects. The transactions had True Interest Costs of 5.48%, 5.67% and 5.90%, respectively.

On October 11, 2007, SCPPA issued $504.4 million of Gas Project Revenue Bonds for the acquisition of the Prepaid Natural Gas Project No.1. The bonds consisted of $302.9 million of 2007 Series A Fixed Rate Bonds and $201.5 million of 2007 Series B LIBOR Index Rate Bonds. These bonds are limited, non-recourse obligations of the Authority payable from and secured solely by the Trust Estate pledged under the Indenture, which includes payments made to the Authority pursuant to the Gas Supply Contracts.

Derivative Instruments

On October 3, 2007 SCPPA entered into an interest rate swap agreement in connection with the issuance of the 2007 Series B Bonds. The swap hedges the interest-rate risk on the LIBOR floating-rate bonds, where SCPPA pays the swap counterparty a fixed rate of 5.0475% in exchange for receiving 67% of 3-month LIBOR plus 1.47%. The floating index on the Swap exactly matches the coupon on the Bonds therefore providing a hedge with no tax or basis risk.

SCPPA also entered into a floating-to-fixed commodity price swap agreement in order to hedge against reductions in its gas sale revenues resulting from changes in monthly market index prices. SCPPA pays the swap counterparty a floating natural gas price over a thirty-year period and receives specified fixed natural gas prices at an agreed pricing point (currently SoCal border) as determined in the Gas Sales Agreements. The swap become effective on July 1, 2008 and expires on September 30, 2038. The fair market value of the commodity price swap agreement is not currently available.

The fair values of the outstanding swaps as of March 31, 2008, are shown below:

	Estimated Fair Value of Swap Agreements (Amounts in thousands)			
	March 31, 2008	December 31, 2007	September 28, 2007	June 29, 2007
NGP 2007 Swap	$ (20,590)	$ (8,096)	$ -	$ -
MPP 2007 Swap	(5,978)	(3,163)	(6)	3,056
MPP 2007 Swap	(5,978)	(3,163)	(6)	3,056
MA 2007 Swap	6,505	3,699	1,645	579
STS 2006 Amended Swap	4,449	4,054	3,114	2,205
STS 2004 Swap	-	-	-	71
MP 2004 Swap	(3,119)	(7,030)	(1,260)	(569)
MA 2004 Swap	(10,404)	(2,111)	(4,185)	(1,871)
STS 2003 Swap	(2,475)	(773)	740	1,960
STS Swaption/ Swap	(24,287)	(22,738)	(16,797)	(12,924)
STS 2001 Swap	(10,261)	(9,529)	(7,957)	(5,427)
STS 1991 Swap	(62,027)	(55,623)	(51,344)	(47,214)
	$ (134,165)	$ (104,473)	$ (76,056)	$ (57,078)

Using This Financial Report

This unaudited 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 costs with respect to such projects. The gas supply contracts with the participants of the Prepaid Natural Gas Project, however, are on a "take-and-pay" basis.

Combined Financial Statements – The Combined Financial Statements 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.

Management's Discussion and Analysis (Continued)

The following table summarizes the financial condition and changes in Net Assets (Deficit) of the Authority as of and for the nine months ended March 31, 2008 and 2007:

Summary of Financial Condition and Changes in Net Assets (Deficit)
($ in thousands)

	March	
	2008	2007
Assets		
Net utility plant	$ 1,017,279	$ 1,014,382
Investments	666,466	526,531
Cash and cash equivalents	112,888	144,665
Prepaid Natural Gas	480,600	-
Other	116,501	124,181
Total assets	$ 2,393,734	$ 1,809,759
Liabilities and Net Assets (Deficit)		
Noncurrent liabilities	$ 2,329,019	$ 1,843,476
Current liabilities	226,373	187,886
Total liabilities	2,555,392	2,031,362
Net assets (deficit)		
Invested in capital assets, net of related debt	(1,246,026)	(730,582)
Restricted net assets	525,669	427,237
Unrestricted net assets	558,699	81,742
Total net deficit	(161,658)	(221,603)
Total liabilities and net assets (deficit)	$ 2,393,734	$ 1,809,759
Revenues, Expenses and Changes in Net Assets (Deficit)		
Operating revenues	$ 338,430	$ 286,084
Operating expenses	(230,936)	(213,410)
Operating income	107,494	72,674
Investment income	27,632	25,658
Debt expense	(81,263)	(81,834)
Change in net deficit	53,863	16,498
Net Deficit, beginning of year	(217,083)	(246,532)
Net contribution by participants	1,562	8,431
Net deficit - end of period	$ (161,658)	$ (221,603)

Net Deficit

The Authority's Net Deficit decreased by $60 million mainly due to an increase in Assets of $584 million offset by an increase in Liabilities of $524 million.

The increase of $584 million in the Authority's Assets is due to the following:

- Utility Plant – increased by $3 million primarily due to the ongoing capital improvements in the Palo Verde, San Juan, Magnolia and Barnett Natural Gas Reserve Project offset by the scheduled depreciation in all Projects.

- Investments – increased by $140 million largely due to the $61 million bond proceeds from the issuance of Natural Gas Project A, 2008 Revenue Bonds; $25 million bond proceeds remaining from the issuance of the Gas Project Revenue Project No. 1 Series 2007 A & B Bonds; $35 million net reclassification of investments from Short-term to Long-term in the Palo Verde, San Juan, STS, Pinedale, Mead Adelanto and Mead Phoenix Projects; $9 million accumulated overbillings and advances from Mead Phoenix and Pinedale; $9 million bond proceeds from Magnolia Power Project Refunding Revenue 2007-1 Bonds; increase in the participants contribution of $4 million in the Project Stabilization Fund ("PSF"); and $10 million reinvestment of interest earnings in Decommissioning Fund, Multiple Project and PSF. The increases were offset by $5 million scheduled draw down from the FSA Guaranteed Investment Contract ("GIC") which provides the monthly withdrawal for payments of the notes due to the participants and $8 million prepayment of nuclear fuel and O&M in the Palo Verde Project.

- Cash and cash equivalents – decreased $32 million primarily due to $35 million net reclassification of investments from Short-term to Long-term; offset by $2 million of proceeds from the Natural Gas Project A, 2008 Revenue Bonds invested in cash equivalents; and $1 million of overbillings payments returned to the Participants of the Ormat Project.

- Prepaid Natural Gas – $480 million prepayment of a 30-year supply of natural gas on behalf of the Project Participants for the newly acquired Gas Project.

- Other - decreased by $8 million largely due to an accounting adjustment of the $24 million deferred debit in the San Juan Project for the environmental upgrade which is now being expended, and the usage of $3 million inventory in the Magnolia Project, offset by $13 million unamortized costs of the new Prepaid Natural Gas Project and $6 million increase in accounts receivable due to underbillings in STS and Barnett Natural Gas Reserves Projects.

The increase in the Authority's Liabilities of $524 million is primarily due to the issuance of $504 million Gas Project Revenue Bonds, Project No. 1, 2007 Series A & B and related accrued interest of $9 million; issuance of $141 million Natural Gas Project A, 2008 Revenue Bonds offset by the payoff of $76 million of the Merrill Lynch bridge loan and $57 million principal maturities and related amortization for all projects.

Operating Revenues and Operating Expenses

The increase in Operating Revenues of $52 million is primarily due to the additional billings of $12 million for steam generator replacement program in the Palo Verde Project; $17 million for the anticipated environmental upgrade and recognition of prior overbillings in the San Juan Project; $12 million for the acquisition of the Barnett Natural Gas Reserves Project; $3 million recognition of revenue due to the usage of GE spare parts inventory, $6 million increase of fuel contribution and $2 million operating expenses in the Magnolia Power Project.

The increase in Operating Expenses of $18 million is mainly due to $9 million usage of GE spare parts inventory and fuel costs contributed by the Participants in the Magnolia Power Project and $9 million start up of the Barnett Natural Gas Reserves Project.

Investment Income

Investment income increased by $2 million largely due to increase in participants contribution in PSF and higher market interest rate earned in Multiple Projects and Decommissioning Fund, offset by change in the market value of investment in all projects.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

INDEPENDENT AUDITOR'S REPORT AND COMBINED FINANCIAL STATEMENTS

JUNE 30, 2007 AND 2006

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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, 2007 and 2006. Please read this discussion and analysis in conjunction with the Authority's Combined Financial Statements, which begin on page 23. 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.

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").

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.

ORMAT GEOTHERMAL ENERGY PROJECT
The Authority entered into long term Power Purchase Agreements in December 2005 with divisions of Ormat Technologies, Inc. for up to 20 megawatts ("MW") of electric generation. The Project started delivery of approximately 5 MW in January 2006 from geothermal energy facilities located in Heber, California. This is one of the sources of renewable energy for the project participants and additional megawatts are expected to become available in the future. The City of Anaheim acts as the Scheduling Coordinator on behalf of the Project Participants.

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").

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.

NATURAL GAS PROJECTS

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

BARNETT PROJECT - Natural gas resources in the Barnett shale geological formation in Texas was acquired from Collins and Young Holding, L.L.P ("C&Y") for a total of $84 million with an effective production date of April 1, 2006. The acquisition settled on October 26, 2006 and was completed on December 7, 2006 when the participants, together with TID, exercised their option to purchase additional resources from C&Y. Two of the original participants, LADWP and the City of Glendale, made the decision not to participate but have agreed to pay their respective share of the development costs incurred through October 13, 2006. The Gas Sales Agreements have been revised accordingly to adjust the entitlement shares and product cost shares for the remaining participants.

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.

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, 2007, the members have the following participation percentages in the Authority's operating projects:

	GENERATION					TRANSMISSION			NATURAL GAS	
Participants	Palo Verde Project	Hoover Uprating Project	San Juan Project	Magnolia Power Project	Ormat Geo-thermal Energy Project	Southern Trans-mission System Project	Mead-Phoenix Project	Mead-Adelanto Project	Pinedale Project	Barnett Project
City of Los Angeles	67.0%	-	-	-	-	59.5%	24.8%	35.7%	-	-
City of Anaheim	-	42.6%	-	38.0%	60.0%	17.6%	24.2%	13.5%	35.7%	45.4%
City of Riverside	5.4%	31.9%	-	-	-	10.2%	4.0%	13.5%	-	-
Imperial Irrigation District	6.5%	-	51.0%	-	-	-	-	-	-	-
City of Vernon	4.9%	-	-	-	-	-	-	-	-	-
City of Azusa	1.0%	4.2%	14.7%	-	-	-	1.0%	2.2%	-	-
City of Banning	1.0%	2.1%	9.8%	-	10.0%	-	1.0%	1.3%	-	-
City of Colton	1.0%	3.2%	14.7%	4.2%	-	-	1.0%	2.6%	7.1%	9.1%
City of Burbank	4.4%	16.0%	-	31.0%	-	4.5%	15.4%	11.5%	14.3%	27.3%
City of Glendale	4.4%	-	9.8%	16.5%	15.0%	2.3%	14.8%	11.1%	28.6%	-
City of Cerritos	-	-	-	4.2%	-	-	-	-	-	-
City of Pasadena	4.4%	-	-	6.1%	15.0%	5.9%	13.8%	8.6%	14.3%	18.2%
	100.0%	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 - Pinedale	2030
Natural Gas Project - Barnett	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, Fiscal Agency Agreement, 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.

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 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,		
	2007	2006	2005
Assets			
Net utility plant	$ 1,006,994	$ 995,599	$ 986,292
Investments	556,518	558,497	689,286
Cash and cash equivalents	149,740	80,778	108,240
Other	103,290	112,223	88,015
Total assets	$ 1,816,542	$ 1,747,097	$ 1,871,833
Liabilities and Net Assets (Deficit)			
Noncurrent liabilities	$ 1,842,488	$ 1,806,660	$ 1,961,741
Current liabilities	191,137	186,969	143,123
Total liabilities	2,033,625	1,993,629	2,104,864
Net Assets (Deficit)			
Invested in capital assets, net of related debt	(742,312)	(715,204)	(657,908)
Restricted net assets	429,686	361,732	332,426
Unrestricted net assets	95,543	106,940	92,451
Total net deficit	(217,083)	(246,532)	(233,031)
Total liabilities and net assets (deficit)	$ 1,816,542	$ 1,747,097	$ 1,871,833
Revenues, Expenses and Changes in Net Assets (Deficit) for the year ended June 30			
Operating revenues	$ 390,005	$ 330,987	$ 220,813
Operating expenses	(291,202)	(248,507)	(171,926)
Operating income	98,803	82,480	48,887
Investment income	33,622	18,932	36,631
Debt expense	(113,028)	(106,198)	(106,083)
Loss on extinguishment of debt	-	-	(85,827)
Change in net assets	19,397	(4,786)	(106,392)
Net Deficit, beginning of year	(246,532)	(233,031)	(125,131)
Release of Over Billings From Prior Year	-	-	(22,503)
Net Contributions/(Withdrawals) By Participants	10,052	(8,715)	20,995
Net Deficit, end of year	$ (217,083)	$ (246,532)	$ (233,031)

Combined Financial Statements (Continued)

Net Deficit

During fiscal year 2007, the Authority's net deficit decreased by $29 million, mainly due to the increase in assets of $69 million and the increase in liabilities of $40 million.

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

- Utility plant - increased by $11 million.
  This increase is the net effect of $47 million for the acquisition of the Barnett Natural Gas Reserves, $42 million of capital expenditures in the Palo Verde, San Juan, Magnolia and the Natural Gas Reserve Projects offset by $78 million of scheduled depreciation in all projects.

- Investments - decreased by $2 million.
  This decrease is due to $39 million reallocation of investments from long-term to short-term in the STS, Ormat, Mead-Phoenix, Mead-Adelanto, and Pinedale Projects and the PSF; and $5 million draw down from the FSA investment agreement in the Palo Verde Project. The decreases were offset by an increase of $10 million in contributions by the participants to the PSF, $19 million of proceeds from the 2006A Magnolia Bonds; $8 million reinvestment of interest earnings in Palo Verde and the PSF Funds; and $5 million increase in the market values of the Palo Verde and the PSF.

- Cash and cash equivalents - increased by $69 million.
  This increase is primarily due to $39 million reallocation of investments from long-term to short- term in the STS, Ormat, Mead-Phoenix, Mead-Adelanto, and Pinedale Projects and the PSF; and accumulated collections of $30 million in over billings in all Projects.

- Other assets - decreased by $9 million.
  This decrease is mainly due to a decrease of $6 million in accounts receivable in the Palo Verde Project, because of the higher maintenance expense and lower interest earnings allocated to debt service in fiscal year 2006; and a decrease of $3 million in accounts receivable which reflects lower drilling activity in the Pinedale Project.

The increase in the Authority's liabilities of $40 million is primarily due to the following:

- $36 million increase in long-term debt due to the net effect of the issuance of the 2006A Revenue Bonds, the 2007A Refunding Revenue Bonds and the redemption of a portion of the 2003A Revenue Bonds in the Magnolia Project; $44 million increase for the acquisition of the Barnett Natural Gas Reserves; $10 million increase in advances from participants for capital expenses in the Barnett Project and $4 million increase in advances for maintenance expenses in the Magnolia Power Project; and $3 million increase in arbitrage payable. These increases were offset by $58 million in principal payments and amortization costs on long-term debt in all projects.

Combined Financial Statements (Continued)

During fiscal year 2006, the Pinedale Natural Gas Reserves and the Ormat Geothermal Project were acquired and the callable bonds for the Multiple Project Revenue Bonds, 1989 Series, were redeemed (See Note 5). As a result of these events, long-term investments decreased by $131 million; cash and cash equivalents decreased by $27 million; and liabilities decreased by $111 million. In addition, Utility plant increased by $9 million because of the net effect of the acquisitions; capital expenditures in the Natural Gas Project, ongoing construction in the Magnolia Project; and the accumulated depreciation in all projects. Other Assets increased by $24 million because of increases in accounts receivable in various projects for debt service, capital billings, and gas and oil sales; and the recognition of spare parts inventory in the Magnolia Project.

Net Operating Income
The net increase in operating income by $16 million is due to the net effect of the following:

- Increase in operating revenues of $59 million primarily due to the additional billings of $39 million for operations and maintenance in the Magnolia Power Project which is now in commercial operation; $13 million for the anticipated environmental upgrades in 2008 for the San Juan Project; and $7 million for the newly acquired projects, Ormat and the Barnett Natural Gas Project.

- Increase of $43 million in Operating Expenses mainly due to recognition of $35 million operating expenses in the Magnolia Power Project and $5 million in the Ormat and Barnett Natural Gas Project; and $3 million in the San Juan and Palo Verde Project due to higher cost of coal and nuclear expenses respectively.

During fiscal year 2006, net operating income increased by $34 million primarily due to increased participant's billings of $14 million for higher debt service payments in the Mead-Phoenix and Mead-Adelanto Projects and $8 million for maintenance expenses and debt service payments in the Palo Verde Projects, and $1.5 million recognition of net operating income relating to the start-up of the Natural Gas Projects and $6.5 million relating to the commencement of commercial operation in the Magnolia Power Plant.

Investment Income
- Investment income increased by $15 million mainly due to the increase in market values of investments.

During fiscal 2006, investment income decreased by $18 million due to the use of funds to redeem the callable portion of the Multiple Project Revenue Bonds and the decrease in market value of the long-term securities in the Palo Verde Decommissioning Trust Funds.

Combined Financial Statements (Continued)

Debt Expense
Debt expense increased by $7 million mainly due to:

- $5.5 million increase in debt service costs due to the Magnolia Power Project being in operations for 12 months compared to 9 months of start-up operations in prior year, and the costs related to the issuance of the 2006A Revenue Bonds; and
- $1.5 million of debt service costs related to the acquisition of the Barnett Natural Gas Project.

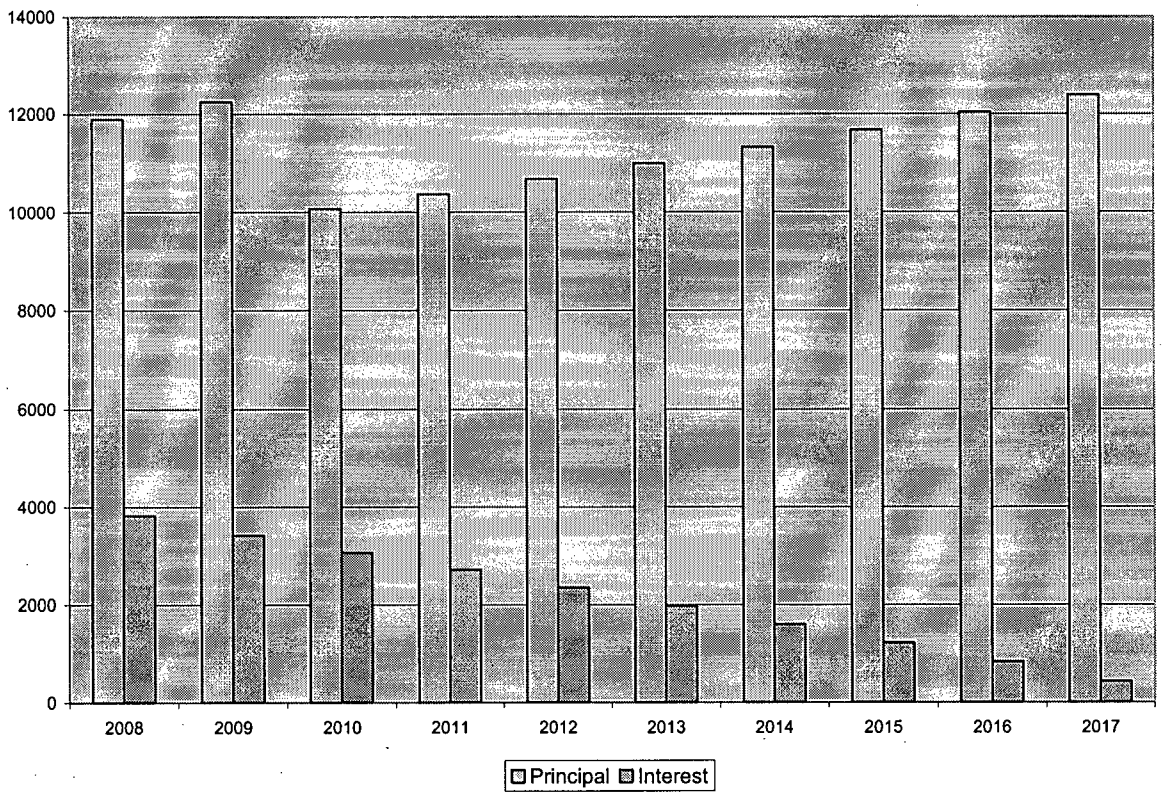
Long-term debt - The Authority has financed the acquisition of most of its Projects through the issuance of revenue bonds. The exception is the Natural Gas Project wherein some of the natural gas participants used cash for their percentage of the acquisition. Capital additions to all of these Projects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

During Fiscal Year 2007, the Authority issued bonds for Magnolia as follows:

- $223,260,000 of Magnolia Power Project A Refunding Revenue Bonds, 2007-1 to refund $202,375,000 of the Magnolia Power Project A Bonds, Revenue Series 2003-1 in June 2007; and
- $37,730,000 of Magnolia Power Project A Revenue Bonds, 2006-1 in July 2006 (See Note 5)

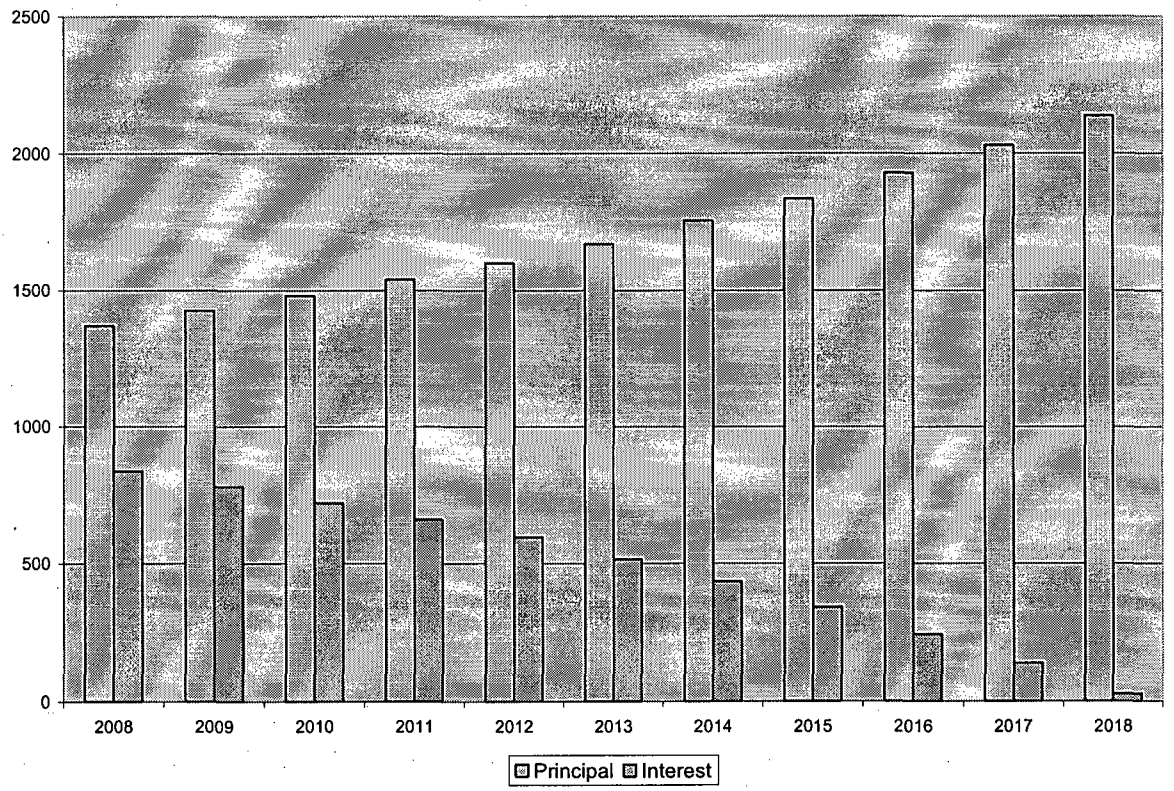
The following graphs for each of the Authority's Projects provide an indication of the principal and interest payments on the bonds that are due each year following June 30, 2007 until the bonds mature. Interest is reflected on an accrual basis.

PALO VERDE PROJECT
Debt Service Requirements
Fiscal Year Ending June 30, 2008 ($ in thousands)



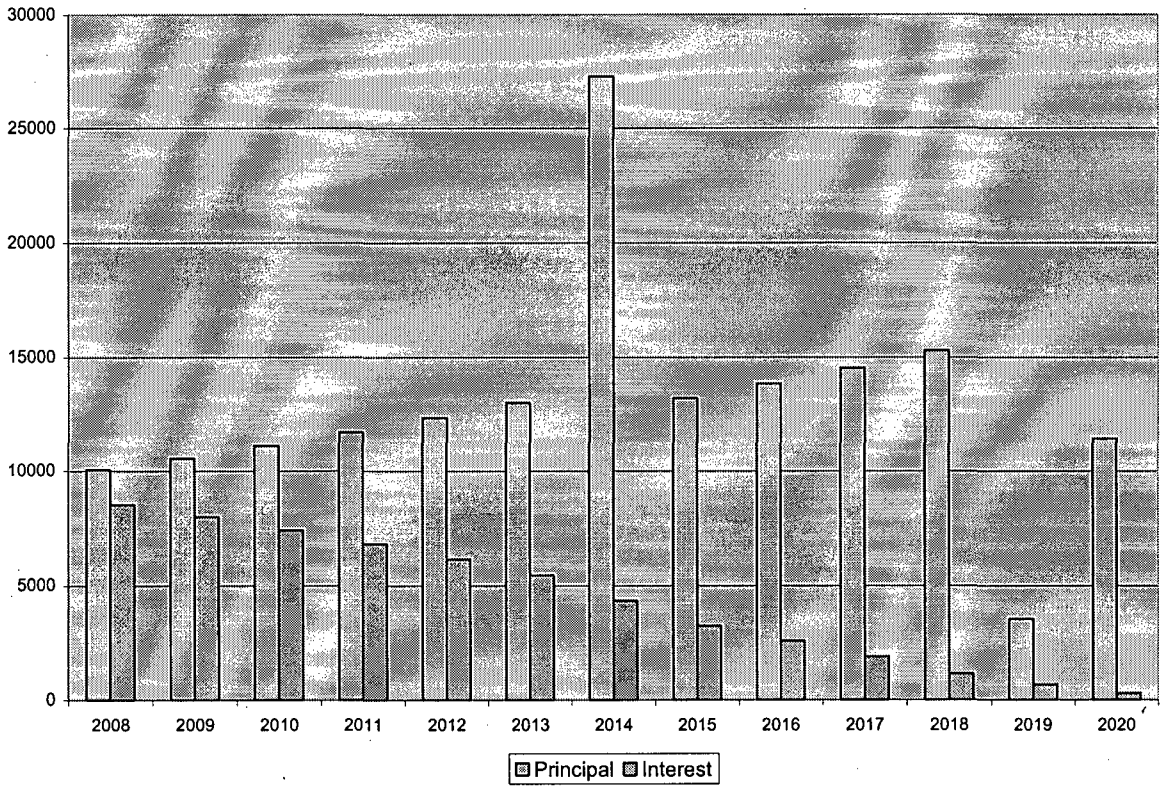
Interest payments on the remaining bonds are payable on the first Wednesday of each month. Principal maturity of $11.5 million was paid on June 6, 2007. The bonds mature in the fiscal year ended June 30, 2017.

HOOVER UPRATING PROJECT
Debt Service Requirements
Fiscal Year Ending June 30, 2008 ($ in thousands)



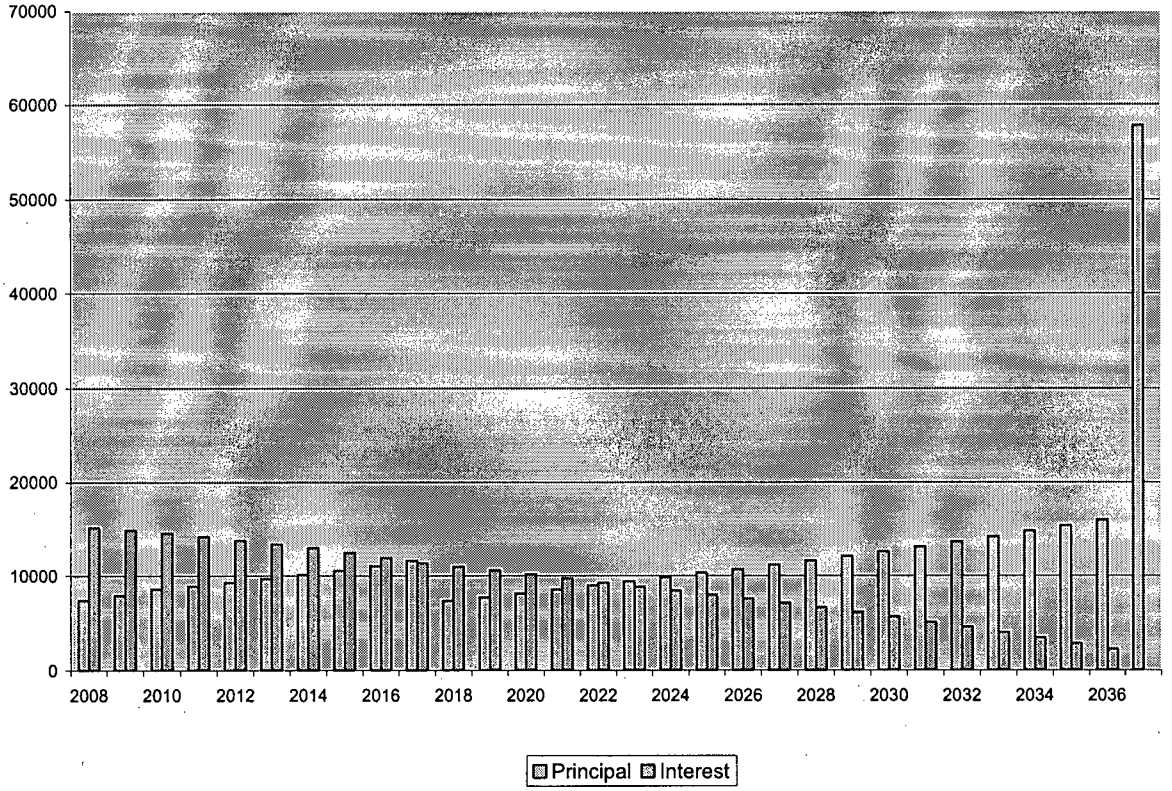
Interest payments on the bonds are payable semi-annually on October 1 and April 1 of each year. Principal maturities of $1.3 million were paid on October 1, 2006. The bonds mature in the fiscal year ended June 30, 2018.

SAN JUAN PROJECT
Debt Service Requirements
Fiscal Year Ending June 30, 2008 ($ in thousands)



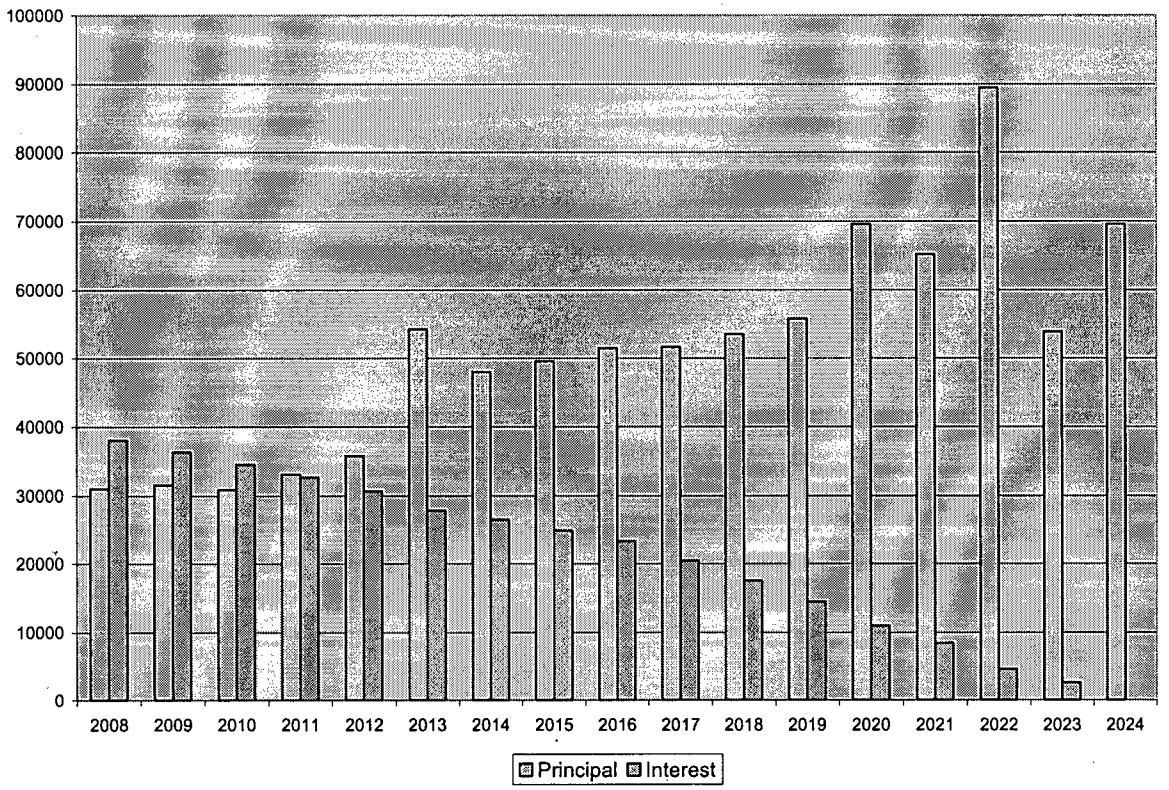
Interest payments on the bonds are payable semi-annually on July 1 and January 1 of each year. Principal maturities of $9.6 million were paid on January 1, 2007. The bonds mature in the fiscal year ended June 30, 2020.

MAGNOLIA POWER PROJECT
Debt Service Requirements
Fiscal Year Ending June 30, 2008 ($ in thousands)



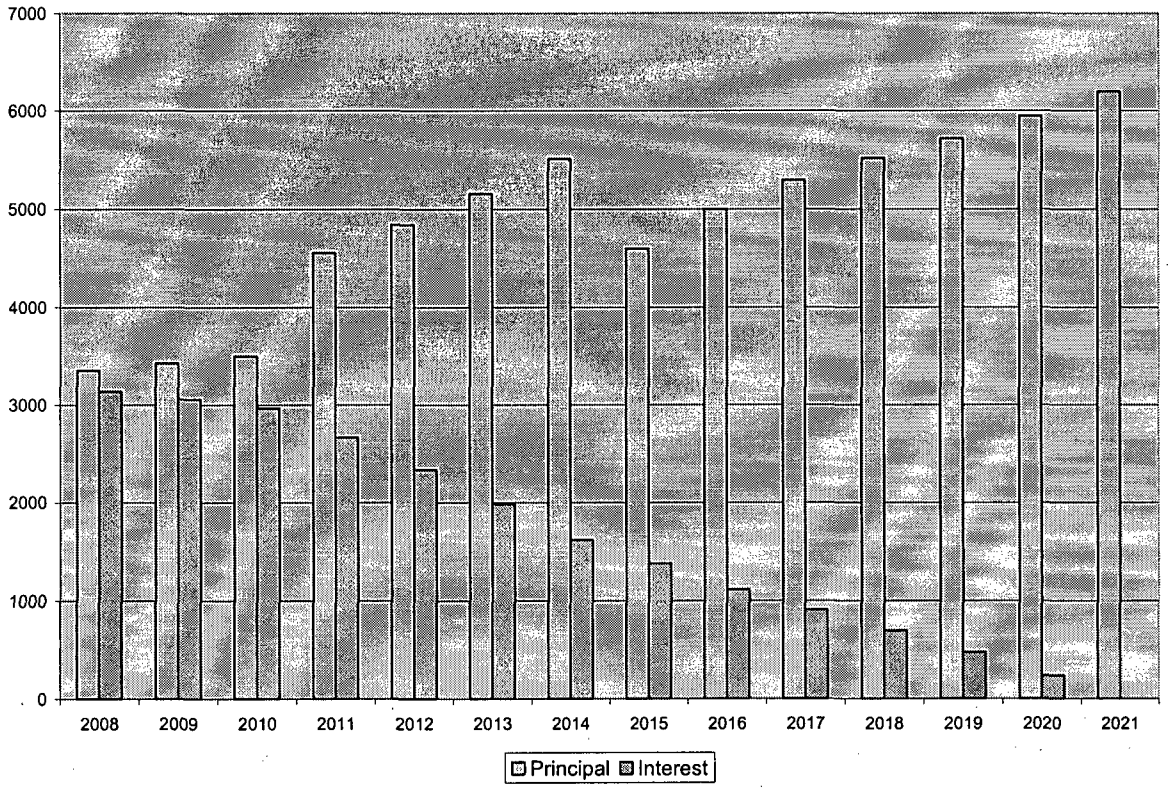
Interest payments on the bonds are payable semi-annually on July 1 and January 1 of each year. Principal maturities of $3.7 million were paid on July 1, 2006, and $202,375,000 par value of bonds were refunded on June 13, 2007. The bonds mature in the fiscal year ended June 30, 2037.

SOUTHERN TRANSMISSION SYSTEM PROJECT
Debt Service Requirements
Fiscal Year Ending June 30, 2008 ($ in thousands)



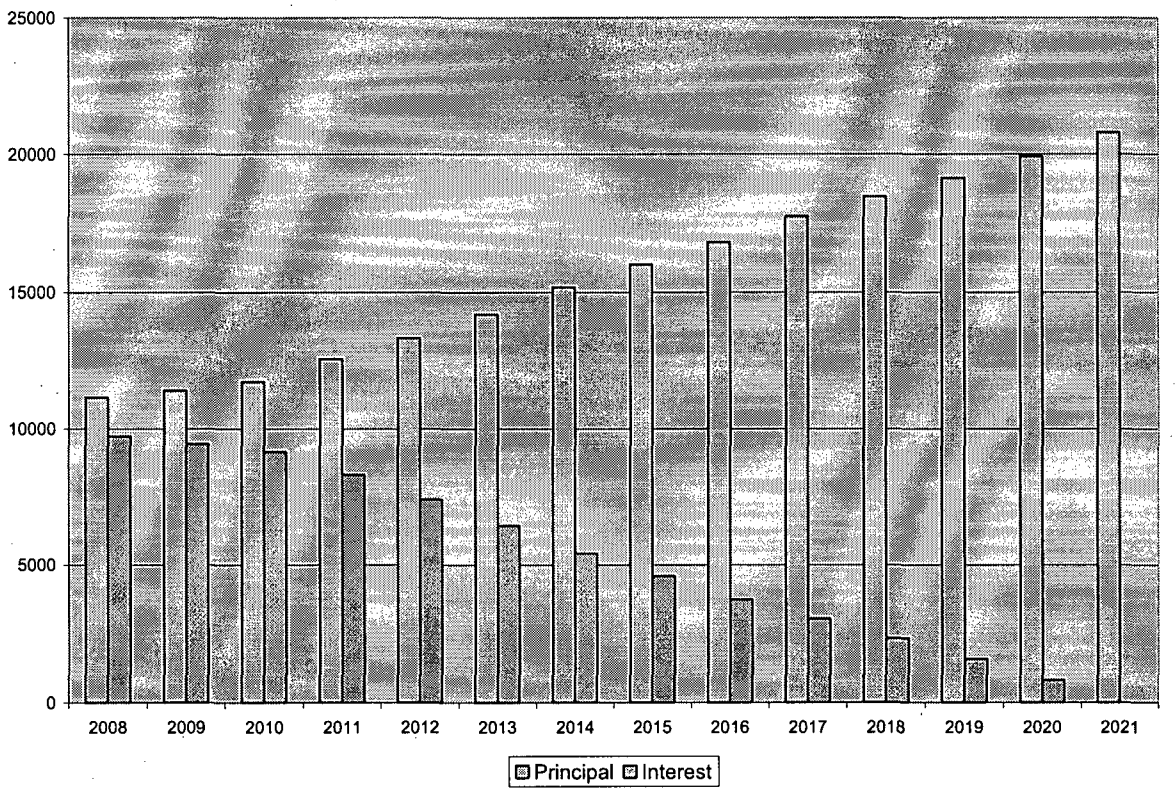
Fixed interest on the bonds is paid semi-annually on July 1 and January 1 of each year. Variable interest is paid monthly, except for the 2003A bonds, which is paid weekly. Principal maturities of $34.2 million were paid on July 1, 2006. The bonds mature in the fiscal year ended June 30, 2024.

MEAD-PHOENIX PROJECT
Debt Service Requirements
Fiscal Year Ending June 30, 2008 ($ in thousands)



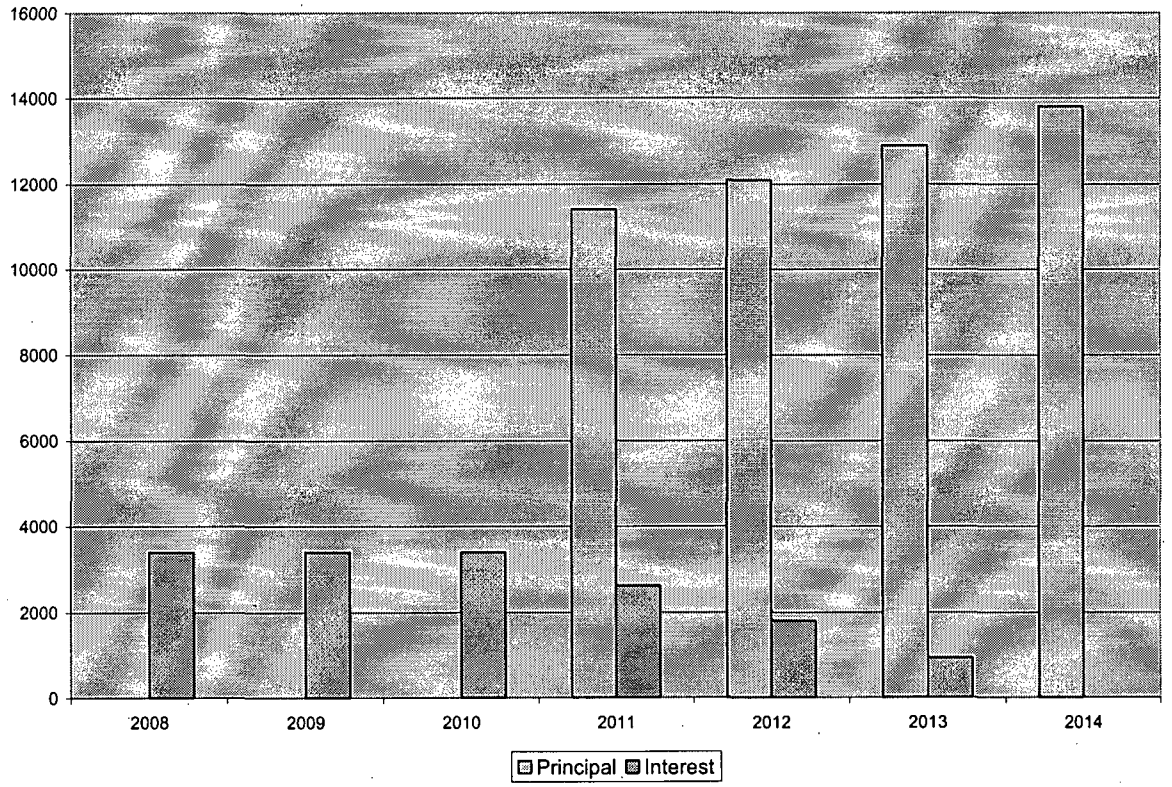
Fixed interest on the bonds is paid semi-annually on July 1 and January 1 of each year. Variable interest is paid weekly. Principal maturities of $3.3 million were paid on July 1, 2006. The bonds mature in the fiscal year ended June 30, 2021.

MEAD-ADELANTO PROJECT
Debt Service Requirements
Fiscal Year Ending June 30, 2008 ($ in thousands)



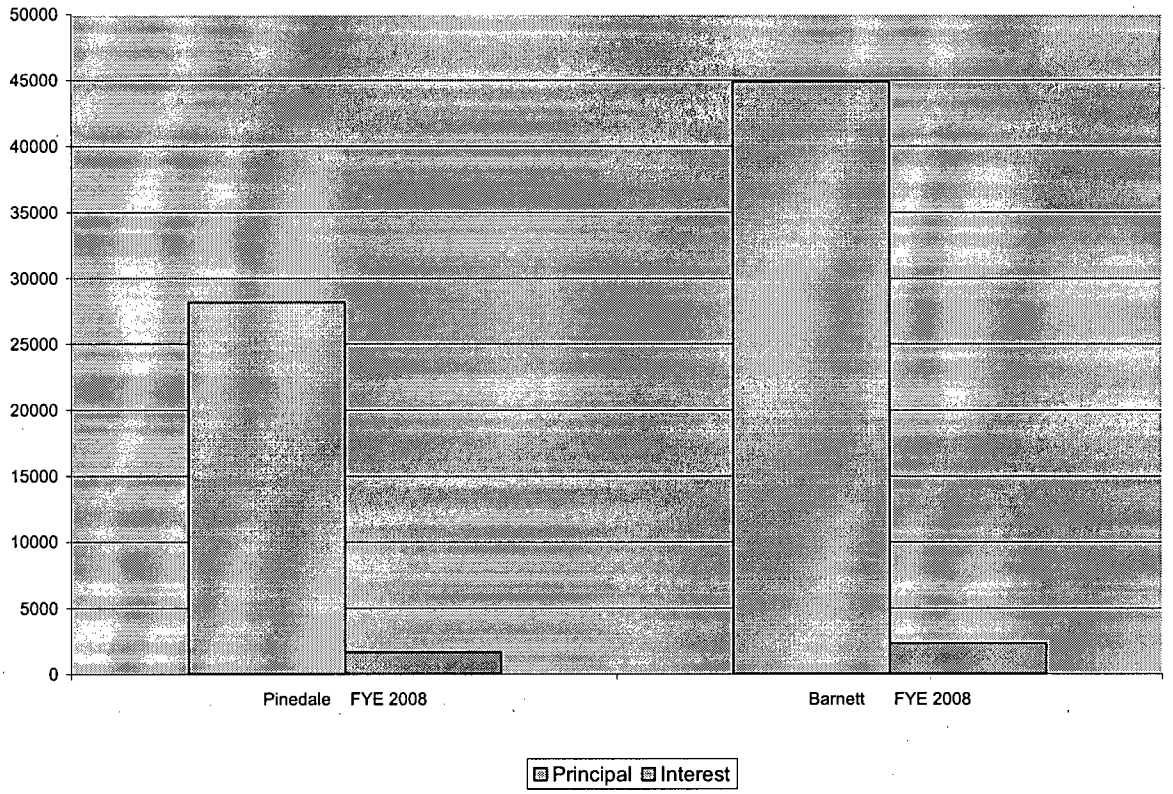
Fixed interest on the bonds is paid semi-annually on July 1 and January 1 of each year. Variable interest is paid Tuesdays, Wednesdays, and Thursdays of every week. Principal maturities of $10.9 million were paid on July 1, 2006. The bonds mature in the fiscal year ended June 30, 2021.

MULTIPLE PROJECT FUND
Debt Service Requirements
Fiscal Year Ending June 30, 2008 ($ 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, 2007. The bonds mature in the fiscal year ended June 30, 2014.

NATURAL GAS PROJECTS
Debt Service Requirements
Fiscal Year Ending June 30, 2008 ($ in thousands)



Interest payments on the outstanding amount of the bonds is payable monthly. There were no principal payments for the year ended June 30, 2007. 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 $198 million to date.

Natural Gas Prepayment Program - The Authority is in the process of negotiating agreements, on behalf of interested participants, for a long-term supply of natural gas through a Prepayment Program. The Natural Gas Prepayment Program consists primarily of the acquisition of the right to receive an aggregate amount of approximately 129 billion cubic feet of natural gas from a Gas Supplier ("supplier") pursuant to the terms of Prepaid Natural Gas Sales Agreements ("agreements"). SCPPA will be able to offer discounted gas to the Project Participants through Gas Supply Contracts ("GSC"). There is a separate GSC with each Project Participant.

The gas will be delivered by the supplier to designated Delivery Points on the natural gas pipelines that serve the Project Participants in specified daily quantities each month over approximately 30-year term of each of the agreements. The supplier is also obligated to make payments to SCPPA for gas not delivered under any agreement for specified reasons, including *force majeure* events. The supplier has also agreed to remarket, on a daily or monthly basis, quantities of gas designated by SCPPA. In the event that the supplier is unable to remarket the gas, the supplier has agreed to purchase such gas for its own account. The agreements will also require the supplier to post collateral sufficient to pay the termination payment and savings amount if the supplier is downgraded below a specified rating. By prepaying the gas supply, SCPPA's participants will be able to procure gas supply at a discounted, fixed price. SCPPA has structured its prepayment program under the strictest compliance with the IRS regulations.

The Authority will issue bonds to prepay the gas supply. Payment from the Participants for the natural gas supply, when delivered, will be sufficient to pay bond debt service. Payment obligation to bondholders shifts to the gas supplier if the supplier defaults or fails to deliver the gas. By entering into a gas price swap, the participants' convert their discounted fixed price to a discounted index price. The swap eliminates price risk and the participants can hedge gas price exposure for various terms at advantageous times in the market, outside of the gas prepayment transaction. This project is in its final completion stage.

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

High Winds Energy Center - 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.

Ameresco Chiquita Energy LLC - 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 Burbank and Pasadena, with their respective shares listed below. This project, which is expected to go on-line December 31, 2008, 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 Burbank	16.6667%
City of Pasadena	83.3333%

Milford Wind Corridor Phase I Project - The Milford Wind Corridor Phase I Project is a 200 MW wind power project planned to be located in the Beaver and Millard Counties, Utah. The wind power will be delivered to SCPPA through the Intermountain Power Project switching station located in Delta, Utah. The terms of the project is 20 years with an expected commercial operation date of December 31, 2008. An early buyout option is included in the agreement after the 10th contract year. There is an anticipated present value cost savings of approximately $42 million as compared to a straight purchase of the facility on the commercial operation date.

Similar to other SCPPA projects, the Milford Wind Corridor Phase I project will be paid for entirely by the participants (LADWP, Burbank, and Pasadena). The project will have no fiscal impact on non-participating members, with the exception of a small decrease in administrative and general expenses. This project is in the final planning stages, approval by the participants is expected in the near future.

Pebble Springs Wind Project - The Pebble Springs Wind Project, a 98.7 MW wind project, is planned to be located in Gilliam County, Oregon. The wind power is scheduled to be delivered to SCPPA through the project substation by December 31, 2008. SCPPA, along with LADWP, Burbank, and Glendale, will be responsible for transporting and scheduling the energy from the project substation to the Project Participants at the Nevada Oregon Border (NOB) through either an agency agreement with LADWP or other means. The terms of the project is 18 years with a right of first offer after the 10th contract year. The right of first offer would give SCPPA the opportunity to purchase the project prior to it being offered for sale to another party. This project is in the final planning stages, approval by the participants is expected in the near future.

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.

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, 2007 and 2006 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, 2007 and 2006 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, as listed in the table of contents, 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 18, 2007

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINED STATEMENTS OF NET ASSETS (DEFICIT)
JUNE 30, 2007
(AMOUNTS IN THOUSANDS)

ASSETS

	GENERATION					TRANSMISSION			NATURAL GAS		MISCELLANEOUS				
	Palo Verde Project	Hoover Uprating Project	San Juan Project	Magnolia Power Project	Ormat Geothermal Energy Project	Southern Transmission System Project	Mead- Phoenix Project	Mead-Adelanto Project	Pinedale Project	Barnett Project	Multiple Project Fund	Projects' Stabilization Fund	Total	Eliminations	Total Combined
ASSETS															
Noncurrent assets															
Utility plant															
Production	$ 650,944	$ -	$ 176,249	$ 278,303	$ -	$ -	$ -	$ -	$ 3,975	$ 822	$ -	$ -	$ 1,110,293	$ -	$ 1,110,293
Transmission	14,076	-	-	15,144	-	674,606	50,770	172,319	-	-	-	-	926,915	-	926,915
General	2,782	21	7,443	14,825	-	18,911	2,640	473	1,063	-	-	-	48,158	-	48,158
Natural gas reserves	-	-	-	-	-	-	-	-	44,747	46,340	-	-	91,087	-	91,087
	667,802	21	183,692	308,272	-	693,517	53,410	172,792	49,785	47,162	-	-	2,176,453	-	2,176,453
Less accumulated depreciation	586,538	21	151,154	19,655	-	409,375	16,237	50,760	4,883	501	-	-	1,239,124	-	1,239,124
	81,264	-	32,538	288,617	-	284,142	37,173	122,032	44,902	46,661	-	-	937,329	-	937,329
Construction work in progress	17,338	-	21,896	23	-	-	236	-	1,573	8,423	-	-	49,489	-	49,489
Nuclear fuel, at amortized cost	20,176	-	-	-	-	-	-	-	-	-	-	-	20,176	-	20,176
Net utility plant	118,778	-	54,434	288,640	-	284,142	37,409	122,032	46,475	55,084	-	-	1,006,994	-	1,006,994
Special funds															
Restricted investments															
Decommissioning funds	141,654	-	-	-	-	-	-	-	-	-	-	-	141,654	-	141,654
Other funds	24,579	2,255	38,089	45,363	-	58,681	7,399	22,628	64	-	66,296	69,969	335,323	-	335,323
	166,233	2,255	38,089	45,363	-	58,681	7,399	22,628	64	-	66,296	69,969	476,977	-	476,977
Unrestricted investments															
Other funds	78,263	1,278	-	-	-	-	-	-	-	-	-	-	79,541	-	79,541
Total special funds	244,496	3,533	38,089	45,363	-	58,681	7,399	22,628	64	-	66,296	69,969	556,518	-	556,518
Other noncurrent assets															
Advance to IPA - restricted	-	-	-	-	-	11,550	-	-	-	-	-	-	11,550	-	11,550
Advances for capacity and energy, net - restricted	-	13,638	-	-	-	-	-	-	-	-	-	-	13,638	-	13,638
Deferred debit	-	-	22,615	1,900	-	-	-	-	-	-	-	-	24,515	-	24,515
Unamortized debt expenses	624	218	1,404	3,580	-	5,937	705	2,333	-	-	-	-	14,801	-	14,801
Other assets	-	-	87	-	-	-	-	-	-	-	-	-	87	-	87
Total other noncurrent assets	624	13,856	24,106	5,480	-	17,487	705	2,333	-	-	-	-	64,591	-	64,591
Total noncurrent assets	363,898	17,389	116,629	339,483	-	360,310	45,513	146,993	46,539	55,084	66,296	69,969	1,628,103	-	1,628,103
Current assets															
Special funds															
Cash and cash equivalents - restricted	6,697	620	9,180	24,497	-	24,622	5,936	15,683	18,255	1,401	8	9,883	116,782	-	116,782
Cash and cash equivalents - unrestricted	7,784	106	3,924	3,452	1,597	4,055	380	650	10,835	175	-	-	32,958	-	32,958
Interest receivable	1,701	31	91	368	9	20	275	836	8	-	2,163	790	6,292	-	6,292
Accounts receivable	686	-	673	2,839	-	1,373	-	-	1,680	1,057	-	-	8,308	-	8,308
Due from other project - restricted	-	-	-	-	-	-	5,396	14,840	-	-	-	-	20,236	(20,236)	-
Materials and supplies	6,537	-	3,519	9,907	-	-	-	-	-	-	-	-	19,963	-	19,963
Prepaid and other assets	176	1,411	349	1,648	-	-	-	-	552	-	-	-	4,136	-	4,136
Total current assets	23,581	2,168	17,736	42,711	1,606	30,070	11,987	32,009	31,330	2,633	2,171	10,673	208,675	(20,236)	188,439
Total assets	$ 387,479	$ 19,557	$ 134,365	$ 382,194	$ 1,606	$ 390,380	$ 57,500	$ 179,002	$ 77,869	$ 57,717	$ 68,467	$ 80,642	$ 1,836,778	$ (20,236)	$ 1,816,542

See accompanying notes.

LIABILITIES AND NET ASSETS (DEFICIT)

	GENERATION					TRANSMISSION			NATURAL GAS		MISCELLANEOUS				
	Palo Verde Project	Hoover Uprating Project	San Juan Project	Magnolia Power Project	Ormat Geothermal Energy Project	Southern Transmission System Project	Mead- Phoenix Project	Mead-Adelanto Project	Pinedale Project	Barnett Project	Multiple Project Fund	Projects' Stabilization Fund	Total	Eliminations	Total Combined
LIABILITIES															
Noncurrent liabilities															
Long-term debt	$ 88,373	$ 15,879	$ 161,540	$ 353,150	$ -	$ 735,641	$ 60,340	$ 192,959	$ 26,900	$ 44,400	$ 42,553	$ -	$ 1,721,735	$ -	$ 1,721,735
Notes payable	51,372	-	-	2,734	-	-	-	-	-	-	-	-	54,106	-	54,106
Advances from participants	-	-	32,000	5,304	-	-	-	-	19,326	10,017	-	-	66,647	-	66,647
Total noncurrent liabilities	139,745	15,879	193,540	361,188	-	735,641	60,340	192,959	46,226	54,417	42,553	-	1,842,488	-	1,842,488
Current liabilities															
Debt due within one year	11,895	1,370	10,050	7,450	-	30,950	3,350	11,150	1,300	500	-	-	78,015	-	78,015
Notes payable due within one year	4,756	-	-	1,232	-	-	-	-	-	-	-	-	5,988	-	5,988
Advances from participants due within one year	-	-	-	14,218	-	-	-	-	18,672	137	-	-	33,027	-	33,027
Accrued interest	316	220	4,384	3,837	-	9,537	1,001	2,884	139	216	1,694	-	24,228	-	24,228
Accounts payable and accruals	18,175	120	3,553	2,020	1,604	6,616	874	2,221	4,747	1,255	-	-	41,185	-	41,185
Accrued property tax	1,800	-	200	-	-	-	-	-	6,694	-	-	-	8,694	-	8,694
Due to other projects	-	-	-	-	-	-	-	-	-	-	20,236	-	20,236	(20,236)	-
Total current liabilities	36,942	1,710	18,187	28,757	1,604	47,103	5,225	16,255	31,552	2,108	21,930	-	211,373	(20,236)	191,137
Total liabilities	176,687	17,589	211,727	389,945	1,604	782,744	65,565	209,214	77,778	56,525	64,483	-	2,053,861	(20,236)	2,033,625
NET ASSETS (DEFICIT)															
Invested in capital assets, net of related debt and advances from participants	19,135	-	(115,751)	(62,980)	-	(476,512)	(25,576)	(79,744)	(1,051)	167	-	-	(742,312)	-	(742,312)
Restricted net assets (deficit)	112,415	699	33,590	42,805	-	85,335	18,003	51,102	63	1,048	3,984	80,642	429,686	-	429,686
Unrestricted net assets (deficit)	79,242	1,269	4,799	12,424	2	(1,187)	(492)	(1,570)	1,079	(23)	-	-	95,543	-	95,543
Total net assets (deficit)	210,792	1,968	(77,362)	(7,751)	2	(392,364)	(8,065)	(30,212)	91	1,192	3,984	80,642	(217,083)	-	(217,083)
Total liabilties and net assets (deficit)	$ 387,479	$ 19,557	$ 134,365	$ 382,194	$ 1,606	$ 390,380	$ 57,500	$ 179,002	$ 77,869	$ 57,717	$ 68,467	$ 80,642	$ 1,836,778	$ (20,236)	$ 1,816,542

See accompanying notes.

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

ASSETS

	GENERATION					TRANSMISSION			NATURAL GAS	MISCELLANEOUS				
	Palo Verde Project	Hoover Uprating Project	San Juan Project	Magnolia Power Project	Ormat Geothermal Project	Southern Transmission System Project	Mead- Phoenix Project	Mead- Adelanto Project	Natural Gas Project	Multiple Project Fund	Projects' Stabilization Fund	Total	Eliminations	Total Combined
ASSETS														
Noncurrent assets														
Utility plant														
Production	$ 647,672	$ -	$ 173,713	$ 277,109	$ -	$ -	$ -	$ -	$ 592	$ -	$ -	$ 1,099,086	$ -	$ 1,099,086
Transmission	14,076	-	-	15,079	-	674,606	50,770	172,319	-	-	-	926,850	-	926,850
General	2,770	21	7,443	14,761	-	18,911	2,640	473	693	-	-	47,712	-	47,712
Natural gas reserves	-	-	-	-	-	-	-	-	44,747	-	-	44,747	-	44,747
	664,518	21	181,156	306,949	-	693,517	53,410	172,792	46,032	-	-	2,118,395	-	2,118,395
Less accumulated depreciation	560,670	21	137,888	8,492	-	390,618	14,834	46,260	2,646	-	-	1,161,429	-	1,161,429
	103,848	-	43,268	298,457	-	302,899	38,576	126,532	43,386	-	-	956,966	-	956,966
Construction work in progress	12,401	-	6,570	-	-	-	80	-	3,752	-	-	22,803	-	22,803
Nuclear fuel, at amortized cost	15,830	-	-	-	-	-	-	-	-	-	-	15,830	-	15,830
Net utility plant	132,079	-	49,838	298,457	-	302,899	38,656	126,532	47,138	-	-	995,599	-	995,599
Special funds														
Restricted investments														
Escrow accounts	-	-	-	-	-	6,535	-	-	-	-	-	6,535	-	6,535
Decommissioning funds	133,489	-	-	-	-	-	-	-	-	-	-	133,489	-	133,489
Other funds	23,629	2,813	38,589	26,241	1,733	64,669	11,394	33,939	3,705	65,395	63,018	335,125	-	335,125
Total restricted investments	157,118	2,813	38,589	26,241	1,733	71,204	11,394	33,939	3,705	65,395	63,018	475,149	-	475,149
Unrestricted investments														
Other funds	82,788	560	-	-	-	-	-	-	-	-	-	83,348	-	83,348
Total special funds	239,906	3,373	38,589	26,241	1,733	71,204	11,394	33,939	3,705	65,395	63,018	558,497	-	558,497
Other noncurrent assets														
Advance to IPA - restricted	-	-	-	-	-	11,550	-	-	-	-	-	11,550	-	11,550
Advances for capacity and energy, net - restricted	-	16,405	-	-	-	-	-	-	-	-	-	16,405	-	16,405
Deferred debit	-	-	23,853	-	-	-	-	-	-	-	-	23,853	-	23,853
Unamortized debt expenses	784	269	1,653	5,038	-	6,642	807	2,673	108	-	-	17,974	-	17,974
Other assets	-	-	70	-	-	-	-	-	-	-	-	70		70
Total other noncurrent assets	784	16,674	25,576	5,038	-	18,192	807	2,673	108	-	-	69,852	-	69,852
Total noncurrent assets	372,769	20,047	114,003	329,736	1,733	392,295	50,857	163,144	50,951	65,395	63,018	1,623,948	-	1,623,948
Current assets														
Special funds														
Cash and cash equivalents - restricted	1,824	18	5,081	11,278	611	15,497	1,883	3,567	3,685	-	3,075	46,519	-	46,519
Cash and cash equivalents - unrestricted	3,776	776	6,113	14,876	-	1,109	291	976	6,342	-	-	34,259	-	34,259
Interest receivable	1,414	29	129	375	7	28	300	848	6	2,130	500	5,766	-	5,766
Accounts receivable	6,934	-	835	2,154	-	1,090	-	-	4,429	-	-	15,442	-	15,442
Due from other project - restricted	-	-	-	-	-	-	5,013	13,787	-	-	-	18,800	(18,800)	-
Materials and supplies	6,711	-	3,427	9,877	-	-	-	-	-	-	-	20,015	-	20,015
Prepaid and other assets	37	-	343	216	-	-	-	-	552	-	-	1,148	-	1,148
Total current assets	20,696	823	15,928	38,776	618	17,724	7,487	19,178	15,014	2,130	3,575	141,949	(18,800)	123,149
Total assets	$ 393,465	$ 20,870	$ 129,931	$ 368,512	$ 2,351	$ 410,019	$ 58,344	$ 182,322	$ 65,965	$ 67,525	$ 66,593	$ 1,765,897	$ (18,800)	$ 1,747,097

See accompanying notes.

LIABILITIES AND NET ASSETS (DEFICIT)

	GENERATION					TRANSMISSION			NATURAL GAS	MISCELLANEOUS				
	Palo Verde Project	Hoover Uprating Project	San Juan Project	Magnolia Power Project	Ormat Geothermal Project	Southern Transmission System Project	Mead- Phoenix Project	Mead- Adelanto Project	Natural Gas Project	Multiple Project Fund	Projects' Stabilization Fund	Total	Eliminations	Total Combined
LIABILITIES														
Noncurrent liabilities														
Long-term debt	$ 98,215	$ 16,821	$ 171,715	$ 316,740	$ -	$ 755,702	$ 63,154	$ 202,596	$ 28,200	$ 41,279	$ -	$ 1,694,422	$ -	$ 1,694,422
Notes payable	55,736	-	-	3,965	-	-	-	-	-	-	-	59,701	-	59,701
Advances from participants	-	-	32,000	1,510	-	-	-	-	19,027	-	-	52,537	-	52,537
Total noncurrent liabilities	153,951	16,821	203,715	322,215	-	755,702	63,154	202,596	47,227	41,279	-	1,806,660	-	1,806,660
Current liabilities														
Debt due within one year	11,545	1,315	9,570	3,735	-	34,230	3,250	10,850	-	-	-	74,495	-	74,495
Notes payable due within one year	4,526	-	-	1,182	-	-	-	-	-	-	-	5,708	-	5,708
Advances from participants due within one year	-	-	-	26,652	-	-	-	-	6,643	-	-	33,295		33,295
Accrued interest	360	233	4,624	7,662	-	9,402	960	2,824	145	1,694	-	27,904	-	27,904
Accounts payable and accruals	11,039	106	3,510	11,507	2,344	1,596	531	1,050	7,087	-	-	38,770	-	38,770
Accrued property tax	1,830	-	219	-	-	-	-	-	4,748	-	-	6,797	-	6,797
Due to other projects	-	-	-	-	-	-	-	-	-	18,800	-	18,800	(18,800)	-
Total current liabilities	29,300	1,654	17,923	50,738	2,344	45,228	4,741	14,724	18,623	20,494	-	205,769	(18,800)	186,969
Total liabilities	183,251	18,475	221,638	372,953	2,344	800,930	67,895	217,320	65,850	61,773	-	2,012,429	(18,800)	1,993,629
NET ASSETS (DEFICIT)														
Invested in capital assets, net of related debt and advances from participants	23,103	-	(129,794)	(15,332)	-	(480,390)	(26,941)	(84,242)	(1,608)	-	-	(715,204)	-	(715,204)
Restricted net assets (deficit)	99,600	1,163	31,027	(996)	-	88,876	17,630	49,317	2,769	5,752	66,594	361,732	-	361,732
Unrestricted net assets (deficit)	87,511	1,232	7,060	11,887	7	603	(240)	(73)	(1,046)	-	(1)	106,940	-	106,940
Total net assets (deficit)	210,214	2,395	(91,707)	(4,441)	7	(390,911)	(9,551)	(34,998)	115	5,752	66,593	(246,532)	-	(246,532)
Total liabilities and net assets (deficit)	$ 393,465	$ 20,870	$ 129,931	$ 368,512	$ 2,351	$ 410,019	$ 58,344	$ 182,322	$ 65,965	$ 67,525	$ 66,593	$ 1,765,897	$ (18,800)	$ 1,747,097

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, 2007
(AMOUNTS IN THOUSANDS)

	GENERATION					TRANSMISSION			NATURAL GAS		MISCELLANEOUS		
	Palo Verde Project	Hoover Uprating Project	San Juan Project	Magnolia Power Project	Ormat Geothermal Project	Southern Transmission System Project	Mead- Phoenix Project	Mead- Adelanto Project	Pinedale Project	Barnett Project	Multiple Project Fund	Projects' Stabilization Fund	Total Combined
Operating revenues													
Sales of electric energy	$ 66,398	$ 2,345	$ 82,857	$ 108,473	$ 3,815	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 263,888
Sales of transmission services	-	-	-	-	-	84,569	7,248	21,147	-	-	-	-	112,964
Sales of natural gas	-	-	-	-	-	-	-	-	8,402	4,751	-	-	13,153
Total operating revenues	66,398	2,345	82,857	108,473	3,815	84,569	7,248	21,147	8,402	4,751	-	-	390,005
Operating expenses													
Operations and maintenance	34,557	2,838	48,502	87,190	3,935	17,238	1,094	1,625	4,621	1,535	-	-	203,135
Depreciation, depletion and amortization	18,453	-	10,573	11,162	-	18,757	1,403	4,500	2,237	501	-	-	67,586
Amortization of nuclear fuel	8,702	-	-	-	-	-	-	-	-	-	-	-	8,702
Decommissioning	8,666	-	3,113	-	-	-	-	-	-	-	-	-	11,779
Total operating expenses	70,378	2,838	62,188	98,352	3,935	35,995	2,497	6,125	6,858	2,036	-	-	291,202
Operating income (loss)	(3,980)	(493)	20,669	10,121	(120)	48,574	4,751	15,022	1,544	2,715	-	-	98,803
Non operating revenues (expenses)													
Investment income	11,513	211	2,808	3,170	115	4,369	757	2,140	180	31	4,331	3,997	33,622
Debt expense	(6,955)	(145)	(9,132)	(16,601)	-	(54,396)	(4,022)	(12,376)	(1,748)	(1,554)	(6,099)	-	(113,028)
Net non operating revenues (expenses)	4,558	66	(6,324)	(13,431)	115	(50,027)	(3,265)	(10,236)	(1,568)	(1,523)	(1,768)	3,997	(79,406)
Change in net assets (deficit)	578	(427)	14,345	(3,310)	(5)	(1,453)	1,486	4,786	(24)	1,192	(1,768)	3,997	19,397
Net assets (deficit) - beginning of year	210,214	2,395	(91,707)	(4,441)	7	(390,911)	(9,551)	(34,998)	115	-	5,752	66,593	(246,532)
Net contributions by participants	-	-	-	-	-	-	-	-	-	-	-	10,052	10,052
Net assets (deficit) - end of year	$ 210,792	$ 1,968	$ (77,362)	$ (7,751)	$ 2	$ (392,364)	$ (8,065)	$ (30,212)	$ 91	$ 1,192	$ 3,984	$ 80,642	$ (217,083)

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)

	GENERATION					TRANSMISSION			NATURAL GAS	MISCELLANEOUS		
	Palo Verde Project	Hoover Uprating Project	San Juan Project	Magnolia Power Project	Ormat Geothermal Project	Southern Transmission System Project	Mead- Phoenix Project	Mead- Adelanto Project	Natural Gas Project	Multiple Project Fund	Projects' Stabilization Fund	Total Combined
Operating revenues												
Sales of electric energy	$ 68,739	$ 2,359	$ 69,123	$ 69,837	$ 886	$ -	$ -	$ -	$ -	$ -	$ -	$ 210,944
Sales of transmission services	-	-	-	-	-	84,061	7,017	20,722	-	-	-	111,800
Sales of natural gas	-	-	-	-	-	-	-	-	8,243	-	-	8,243
Total operating revenues	68,739	2,359	69,123	69,837	886	84,061	7,017	20,722	8,243	-	-	330,987
Operating expenses												
Operations and maintenance	33,714	2,575	46,883	54,873	914	17,300	1,119	1,417	4,150	-	-	162,945
Depreciation, depletion and amortization	18,274	-	10,489	8,492	-	19,629	1,403	4,500	2,646	-	-	65,433
Amortization of nuclear fuel	6,860	-	-	-	-	-	-	-	-	-	-	6,860
Decommissioning	10,156	-	3,113	-	-	-	-	-	-	-	-	13,269
Total operating expenses	69,004	2,575	60,485	63,365	914	36,929	2,522	5,917	6,796	-	-	248,507
Operating income (loss)	(265)	(216)	8,638	6,472	(28)	47,132	4,495	14,805	1,447	-	-	82,480
Non operating revenues (expenses)												
Investment income	2,533	97	2,112	988	35	4,802	742	2,082	101	4,245	1,195	18,932
Debt expense	(7,273)	(419)	(9,461)	(11,901)	-	(54,303)	(3,735)	(11,580)	(1,433)	(6,093)	-	(106,198)
Loss on extinguishment of debt	-	-	-	-	-	-	-	-	-	-	-	-
Net non operating revenues (expenses)	(4,740)	(322)	(7,349)	(10,913)	35	(49,501)	(2,993)	(9,498)	(1,332)	(1,848)	1,195	(87,266)
Change in net assets (deficit)	(5,005)	(538)	1,289	(4,441)	7	(2,369)	1,502	5,307	115	(1,848)	1,195	(4,786)
Net assets (deficit) - beginning of year	215,219	2,933	(92,996)	-	-	(388,542)	(11,053)	(40,305)	-	7,600	74,113	(233,031)
Release of over billings from prior years	-	-	-	-	-	-	-	-	-	-	-	-
Net withdrawal by participants	-	-	-	-	-	-	-	-	-	-	(8,715)	(8,715)
Net assets (deficit) - end of year	$ 210,214	$ 2,395	$ (91,707)	$ (4,441)	$ 7	$ (390,911)	$ (9,551)	$ (34,998)	$ 115	$ 5,752	$ 66,593	$ (246,532)

See accompanying notes.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINED STATEMENTS OF CASH FLOWS
FOR THE YEAR ENDED JUNE 30, 2007
(AMOUNTS IN THOUSANDS)

	GENERATION					TRANSMISSION			NATURAL GAS		MISCELLANEOUS		
	Palo Verde Project	Hoover Uprating Project	San Juan Project	Magnolia Power Project	Ormat Geothermal Energy Project	Southern Transmission System Project	Mead- Phoenix Project	Mead- Adelanto Project	Pinedale Project	Barnett Project	Multiple Project Fund	Projects' Stabilization Fund	Total Combined
Cash flows from operating activities													
Receipts from participants	$ 71,033	$ 2,354	$ 84,144	$ 58,352	$ 3,015	$ 87,781	$ 7,209	$ 21,118	$ 9,945	$ 2,784	$ -	$ -	$ 347,735
Receipts from sale of oil and gas	-	-	-	-	-	-	-	-	17,327	1,008	-	-	18,335
Payments to operating managers	(33,658)	(257)	(48,344)	(47,967)	(3,875)	(17,521)	(1,261)	(1,485)	(24,287)	(1,177)	-	-	(179,832)
Other disbursements and receipts	7,633	-	-	-	(7)	-	167	-	(2)	12	-	-	7,803
Net cash flows from operating activities	45,008	2,097	35,800	10,385	(867)	70,260	6,115	19,633	2,983	2,627	-	-	194,041
Cash flows from noncapital financing activities													
Advances (withdrawals) by participants, net	-	-	-	(10,538)	-	-	-	-	15,349	10,458	-	10,052	25,321
Cash flows from capital financing activities													
Additions to plant, net	(22,058)	-	(18,432)	(2,232)	-	-	(156)	-	(2,126)	(55,101)	-	-	(100,105)
Debt interest payments	(4,650)	(906)	(9,247)	(16,026)	-	(40,876)	(3,350)	(10,457)	(1,640)	(1,339)	(3,389)	-	(91,880)
Proceeds from sale of bonds	-	-	-	261,892	-	-	-	-	-	44,900	-	-	306,792
Payment for defeasance of revenue bonds	-	-	-	(219,059)	-	-	-	-	-	-	-	-	(219,059)
Transfer of funds from escrow	-	-	-	-	-	6,535	-	-	-	-	-	-	6,535
Principal payments on debt	(11,545)	(1,315)	(9,570)	(4,917)	-	(34,230)	(3,250)	(10,850)	-	-	-	-	(75,677)
Payment for bond issue costs	-	-	-	(2,125)	-	-	-	-	-	-	-	-	(2,125)
Net cash used for capital and related financing activities	(38,253)	(2,221)	(37,249)	17,533	-	(68,571)	(6,756)	(21,307)	(3,766)	(11,540)	(3,389)	-	(175,519)
Cash flows from investing activities													
Interest received on investments	2,098	145	2,392	2,996	113	3,818	755	2,076	808	31	4,298	2,332	21,862
Purchases of investments	(2,177)	(1,326)	(19,482)	(80,695)	-	(33,367)	(1,876)	(4,066)	(60)	-	(8,336)	(73,187)	(224,572)
Proceeds from sale/maturity of investments	2,205	1,237	20,449	62,114	1,740	39,931	5,904	15,454	3,749	-	7,435	67,611	227,829
Net cash provided by (used for) investing activities	2,126	56	3,359	(15,585)	1,853	10,382	4,783	13,464	4,497	31	3,397	(3,244)	25,119
Net increase (decrease) in cash and cash equivalents	8,881	(68)	1,910	1,795	986	12,071	4,142	11,790	19,063	1,576	8	6,808	68,962
Cash and cash equivalents, beginning of year	5,600	794	11,194	26,154	611	16,606	2,174	4,543	10,027	-	-	3,075	80,778
Cash and cash equivalents, end of year	$ 14,481	$ 726	$ 13,104	$ 27,949	$ 1,597	$ 28,677	$ 6,316	$ 16,333	$ 29,090	$ 1,576	$ 8	$ 9,883	$ 149,740

See accompanying notes.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINED STATEMENTS OF CASH FLOWS
FOR THE YEAR ENDED JUNE 30, 2007
(AMOUNTS IN THOUSANDS)

	GENERATION					TRANSMISSION			NATURAL GAS		MISCELLANEOUS		
	Palo Verde Project	Hoover Uprating Project	San Juan Project	Magnolia Power Project	Ormat Geothermal Energy Project	Southern Transmission System Project	Mead- Phoenix Project	Mead- Adelanto Project	Pinedale Project	Barnett Project	Multiple Project Fund	Projects' Stabilization Fund	Total Combined
Reconciliation of operating income (loss) to net cash provided by operating activities													
Operating income (loss)	$ (3,980)	$ (493)	$ 20,669	$ 10,121	$ (120)	$ 48,574	$ 4,751	$ 15,022	$ 1,544	$ 2,715	$ -	$ -	$ 98,803
Adjustments to reconcile operating income (loss) to net cash provided by operating activities													
Depreciation	18,453	-	10,573	11,162	-	18,757	1,403	4,500	2,237	501	-	-	67,586
Decommissioning	8,666	-	3,113	-	-	-	-	-	-	-	-	-	11,779
Advances for capacity and energy	-	2,583	-	-	-	-	-	-	-	-	-	-	2,583
Amortization of nuclear fuel	8,702	-	-	-	-	-	-	-	-	-	-	-	8,702
Changes in assets and liabilities													-
Accounts receivable	6,247	-	145	46	-	(283)	-	-	(29)	(1,057)	-	-	5,069
Accounts payable and accruals	6,878	7	162	(9,573)	(740)	3,212	(41)	103	278	559	-	-	845
Other	42	-	1,138	(1,371)	(7)	-	2	8	(1,047)	(91)	-	-	(1,326)
					-								
Net cash provided by operating activities	$ 45,008	$ 2,097	$ 35,800	$ 10,385	$ (867)	$ 70,260	$ 6,115	$ 19,633	$ 2,983	$ 2,627	$ -	$ -	$ 194,041
Cash and cash equivalents as stated in the Combined Statements of Net Assets (Deficit)													
Cash and cash equivalents - restricted	$ 6,697	$ 620	$ 9,180	$ 24,497	$ -	$ 24,622	$ 5,936	$ 15,683	$ 18,255	$ 1,401	$ 8	$ 9,883	$ 116,782
Cash and cash equivalents - unrestricted	7,784	106	3,924	3,452	1,597	4,055	380	650	10,835	175	-	-	32,958
	$ 14,481	$ 726	$ 13,104	$ 27,949	$ 1,597	$ 28,677	$ 6,316	$ 16,333	$ 29,090	$ 1,576	$ 8	$ 9,883	$ 149,740

See accompanying notes.

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

	GENERATION					TRANSMISSION			NATURAL GAS	MISCELLANEOUS		
	Palo Verde Project	Hoover Uprating Project	San Juan Project	Magnolia Power Project	Ormat Geothermal Energy Project	Southern Transmission System Project	Mead- Phoenix Project	Mead- Adelanto Project	Natural Gas Project	Multiple Project Fund	Projects' Stabilization Fund	Total Combined
Cash flows from operating activities												
Receipts from participants	$ 49,275	$ 2,351	$ 70,039	$ 78,649	$ 3,031	$ 84,135	$ 7,083	$ 20,666	$ 14,228	$ -	$ -	$ 329,457
Receipts from sale of oil and gas	-	-	-	-	-	-	-	-	16,620	-	-	16,620
Payments to operating managers	(30,082)	(271)	(45,013)	(52,528)	(715)	(18,371)	(1,046)	(1,508)	(18,920)	-	-	(168,454)
Other disbursements and receipts	7,633	-	-	4	-	-	-	-	4	-	-	7,641
Net cash flows from operating activities	26,826	2,080	25,026	26,125	2,316	65,764	6,037	19,158	11,932	-	-	185,264
Cash flows from noncapital financing activities												
Advances (withdrawals) by participants, net	-	-	-	6,512	-	-	-	-	43,860	-	(8,715)	41,657
Cash flows from capital financing activities												
Additions to plant, net	(20,809)	-	(5,421)	(25,531)	-	-	(3)	-	(69,165)	-	-	(120,929)
Debt interest payments	(5,133)	(954)	(8,461)	(15,959)	-	(41,230)	(3,436)	(10,653)	(1,186)	(8,626)	-	(95,638)
Proceeds from notes	-	-	-	6,109	-	-	-	-	-	-	-	6,109
Proceeds from sale of bonds	-	-	-	-	-	-	-	-	29,900	-	-	29,900
Transfer of funds from escrow	-	-	-	-	-	4,200	-	-	-	-	-	4,200
Principal payments on debt	(11,300)	(1,275)	(9,160)	(1,012)	-	(31,470)	-	-	(1,700)	(170,200)	-	(226,117)
Transfer of funds to escrow	-	-	-	-	-	-	-	-	-	(89)	-	(89)
Payment for bond issue costs	-	-	(97)	-	-	-	-	-	(214)	-	-	(311)
Net cash used for capital and related financing activities	(37,242)	(2,229)	(23,139)	(36,393)	-	(68,500)	(3,439)	(10,653)	(42,365)	(178,915)	-	(402,875)
Cash flows from investing activities												
Interest received on investments	1,604	118	1,868	1,471	28	3,239	683	1,884	297	10,437	1,825	23,454
Purchases of investments	(14,254)	(1,774)	(28,558)	(41,284)	(1,733)	(36,500)	(4,537)	(13,430)	(3,697)	(418)	(17,070)	(163,255)
Proceeds from sale/maturity of investments	21,587	1,591	21,479	50,554	-	15,791	1,987	3,853	-	168,896	2,555	288,293
Net cash provided by (used for) investing activities	8,937	(65)	(5,211)	10,741	(1,705)	(17,470)	(1,867)	(7,693)	(3,400)	178,915	(12,690)	148,492
Net increase (decrease) in cash and cash equivalents	(1,479)	(214)	(3,324)	6,985	611	(20,206)	731	812	10,027	-	(21,405)	(27,462)
Cash and cash equivalents, beginning of year	7,079	1,008	14,518	19,169	-	36,812	1,443	3,731	-	-	24,480	108,240
Cash and cash equivalents, end of year	$ 5,600	$ 794	$ 11,194	$ 26,154	$ 611	$ 16,606	$ 2,174	$ 4,543	$ 10,027	$ -	$ 3,075	$ 80,778

See accompanying notes.

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

	GENERATION					TRANSMISSION			NATURAL GAS	MISCELLANEOUS		
	Palo Verde Project	Hoover Uprating Project	San Juan Project	Magnolia Power Project	Ormat Geothermal Energy Project	Southern Transmission System Project	Mead- Phoenix Project	Mead- Adelanto Project	Natural Gas Project	Multiple Project Fund	Projects' Stabilization Fund	Total Combined
Reconciliation of operating income (loss) to net cash provided by operating activities												
Operating income (loss)	$ (265)	$ (216)	$ 8,638	$ 6,472	$ (28)	$ 47,132	$ 4,495	$ 14,805	$ 1,447	$ -	$ -	$ 82,480
Adjustments to reconcile operating income (loss) to net cash provided by operating activities												
Depreciation	18,274	-	10,489	8,492	-	19,629	1,403	4,500	2,646	-	-	65,433
Decommissioning	10,156	-	3,113	-	-	-	-	-	-	-	-	13,269
Advances for capacity and energy	-	2,310	-	-	-	-	-	-	-	-	-	2,310
Amortization of nuclear fuel	6,860	-	-	-	-	-	-	-	-	-	-	6,860
Changes in assets and liabilities												
Accounts receivable	(3,544)	-	(785)	(12,196)	-	(1,046)	30	(7)	(2,058)	-	-	(19,606)
Accounts payable and accruals	(4,695)	(14)	3,745	23,298	2,344	49	106	(145)	9,992	-	-	34,680
Other	40	-	(174)	59		-	3	5	(95)	-	-	(162)
Net cash provided by operating activities	$ 26,826	$ 2,080	$ 25,026	$ 26,125	$ 2,316	$ 65,764	$ 6,037	$ 19,158	$ 11,932	$ -	$ -	$ 185,264
Cash and cash equivalents as stated in the Combined Statements of Net Assets (Deficit)												
Cash and cash equivalents - restricted	$ 1,824	$ 18	$ 5,081	$ 11,278	$ 611	$ 15,497	$ 1,883	$ 3,567	$ 3,685	$ -	$ 3,075	$ 46,519
Cash and cash equivalents - unrestricted	3,776	776	6,113	14,876	-	1,109	291	976	6,342	-	-	34,259
	$ 5,600	$ 794	$ 11,194	$ 26,154	$ 611	$ 16,606	$ 2,174	$ 4,543	$ 10,027	$ -	$ 3,075	$ 80,778

See accompanying notes.

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.

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").

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 ("MPP"). 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.

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

- **Natural Gas Transportation:** SCPPA has an agreement with Southern California Gas Company ("SoGas") for intrastate transmission services. The agreement took effect in January 2005 and will expire in January 2009. SoGas provides transportation, storage, and balancing services of natural gas from the Southern California Border to the MPP Plant.

Note 1 - Organization and Purpose (Continued)

- **Parts and Special Services Agreement:** SCPPA entered into an 18 year agreement with General Electric International ("GE") in September 2005. Currently, the agreement covers only the gas turbine, but effective August 2007, an amendment will be added to the agreement to include coverage for the gas generator, the steam turbine, and the steam generator. GE provides planned and unplanned maintenance, including replacement parts, based on factored fired hours.

Ormat Geothermal Project - The Authority entered into long term Power Purchase Agreements in December 2005 with divisions of Ormat Technologies, Inc. for up to 20 megawatts ("MW") of electric generation. The Project started delivery of approximately 5 MW in January 2006 from geothermal energy facilities located in Heber, California. This is one of the sources of renewable energy for the project participants and additional megawatts are expected to become available in the future. The City of Anaheim acts as the Scheduling Coordinator on behalf of the Project Participants.

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").

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.

Natural Gas Projects

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

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

Note 1 - Organization and Purpose (Continued)

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

Barnett Project - Natural gas resources in the Barnett shale geological formation in Texas was acquired from Collins and Young Holding, L.L.P ("C&Y") for a total of $84 million with an effective production date of April 1, 2006. The acquisition settled on October 26, 2006 and was completed on December 7, 2006 when the participants, together with TID, exercised their option to purchase additional resources from C&Y. Two of the original participants, LADWP and the City of Glendale, made the decision not to participate but have agreed to pay their respective share of the development costs incurred through October 13, 2006. The Gas Sales Agreements have been revised accordingly to adjust the entitlement shares and product cost shares for the remaining participants.

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

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.

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.

Note 1 - Organization and Purpose (Continued)

Participant Ownership Interests - The Authority's participants may elect to participate in the projects. As of June 30, 2007, the members have the following participation percentages in the Authority's operating projects:

	GENERATION					TRANSMISSION			NATURAL GAS	
Participants	Palo Verde Project	Hoover Uprating Project	San Juan Project	Magnolia Power Project	Ormat Geo-thermal Energy Project	Southern Trans-mission System Project	Mead-Phoenix Project	Mead-Adelanto Project	Pinedale Project	Barnett Project
City of Los Angeles	67.0%	-	-	-	-	59.5%	24.8%	35.7%	-	-
City of Anaheim	-	42.6%	-	38.0%	60.0%	17.6%	24.2%	13.5%	35.7%	45.4%
City of Riverside	5.4%	31.9%	-	-	-	10.2%	4.0%	13.5%	-	-
Imperial Irrigation District	6.5%	-	51.0%	-	-	-	-	-	-	-
City of Vernon	4.9%	-	-	-	-	-	-	-	-	-
City of Azusa	1.0%	4.2%	14.7%	-	-	-	1.0%	2.2%	-	-
City of Banning	1.0%	2.1%	9.8%	-	10.0%	-	1.0%	1.3%	-	-
City of Colton	1.0%	3.2%	14.7%	4.2%	-	-	1.0%	2.6%	7.1%	9.1%
City of Burbank	4.4%	16.0%	-	31.0%	-	4.5%	15.4%	11.5%	14.3%	27.3%
City of Glendale	4.4%	-	9.8%	16.5%	15.0%	2.3%	14.8%	11.1%	28.6%	-
City of Cerritos	-	-	-	4.2%	-	-	-	-	-	-
City of Pasadena	4.4%	-	-	6.1%	15.0%	5.9%	13.8%	8.6%	14.3%	18.2%
	100.0%	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 - Pinedale	2030
Natural Gas Project - Barnett	2030
ORMAT Geothermal Project	2031

Note 1 - Organization and Purpose (Continued)

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 Projects 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 54 years. The depletion rate for the Pinedale Project was $1.90/MMbtu and the estimated total net revenue volume was 24,351,608 MMbtu up to the period ending 2060 at June 30, 2007. The depletion rate for the Barnett Project was $1.63/MMbtu and the estimated total net revenue volume was 28,906,440 up to the period ending 2060 at June 30, 2007.

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

	Balance July 1, 2006	Additions	Disposals	Transfers	Balance June 30, 2007
Nondepreciable utility plant					
Land	$ 42,472	$ -	$ -	$ -	$ 42,472
Construction work in progress	19,051	29,256	6	(8,820)	39,493
Contruction work in progress - gas	3,752	9,996	-	(3,752)	9,996
Nuclear fuel*	15,830	10,782	(6,436)	-	20,176
Total nondepreciable utility plant	81,105	50,034	(6,430)	(12,572)	112,137
Depreciable utility plant					
Production					
Nuclear generation (Palo Verde Project)	646,936	4,464	(1,192)	-	650,208
Coal-fired plant (San Juan Unit 3 Project)	173,712	2,956	(419)	-	176,249
Gas-fired plant (Magnolia Power Project)	277,109	1,194	-	-	278,303
Transmission	885,115	65	-	-	885,180
General	47,019	141	(65)	-	47,095
Acquisition of gas reserves	44,747	46,340	-	-	91,087
Intagibles	592	4,205	-	-	4,797
Well equipment and production facilities	693	369	-	-	1,062
Total depreciable utility plant	2,075,923	59,734	(1,676)	-	2,133,981
Less accumulated depreciation	(1,161,429)	(79,365)	1,670	-	(1,239,124)
Total utility plant, net	$ 995,599	$ 30,403	$ (6,436)	$ (12,572)	$ 1,006,994

**Nuclear fuel disposals represent amortization.*

Note 2 - Summary of Significant Accounting Policies (Continued)

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.

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 2006 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 $8.7 million and $10.2 million in fiscal years 2007 and 2006, respectively. The decommissioning liability is included as a component of accumulated depreciation and was $211.4 and $202.7 million at June 30, 2007 and 2006, 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, 2007, decommissioning funds totaled approximately $142.9 million, including approximately $1.2 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 $43.5 million and $40.5 million at June 30, 2007 and 2006, respectively.

As of June 30, 2007, 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. The current portion of these Advances is recorded under Prepaid and Other Assets in the Current Assets Section of the Combined Statements of Net Assets (Deficit).

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

Deferred Debits - Certain expenses which may be subject to amortization in the future or items where final disposition is uncertain is classified as Deferred Debits and the underlying liability is presented in Advances from Participants.

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. 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.

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 $20.2 million ($5.4 million payable to the Mead-Phoenix Project and $14.8 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.

During the fiscal year ended June 30, 2007, the Authority made rebate payments to the IRS of $0.23 million for the STS bonds.

Recorded arbitrage rebate and yield restriction liabilities as of June 30, 2007, were $0.17 million for Palo Verde, $2.06 million for STS, $0.67 million for Mead-Phoenix, and $1.86 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 or debt service costs over the commercial life of the property.

Note 2 - Summary of Significant Accounting Policies (Continued)

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 $60 million and $64.5 million as of June 30, 2007 and 2006, respectively.

Transportation Costs - As a result of the sales and purchases agreements for natural gas entered into by SCPPA, the participants receive less volume than processed incurring embedded transportation costs. These costs are recorded as participants' revenue and expense to the Natural Gas Project. At June 30, 2007, transportation costs were approximately $240,000 for the Pinedale Project and $85,000 for the Barnett Project.

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, 2007 the participants' contribution in kind was approximately 6.7 million MMBtu and was valued at approximately $43.0 million.

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.

Note 3 - Investments (Continued)

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;
- 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.

Note 3 - Investments (Continued)

Investments at June 30, 2007 and 2006 are as follows:

	JUNE 30, 2007											
	GENERATION					TRANSMISSION			NATURAL GAS	MISCELLANEOUS		
	Palo Verde Project	Hoover Uprating Project	San Juan Project	Magnolia Power Project	Ormat Geo thermal Project	Southern Trans-mission System Project	Mead-Phoenix Project	Mead-Adelanto Project	Pinedale & Barnett Project	Multiple Project Fund	Projects' Stabiliza-tion Fund	Total
U.S. Agencies	$ 183,404	$ 2,203	$ 9,954	$ 18,812	$ -	$ -	$ -		$ -	$ -	$ 69,968	$ 284,341
Agency Discount Notes	13,400	1,930	19,301	32,539	1,415	47,889	5,746	15,588	27,005	7,449	7,032	179,294
Treasury Coupon	489	-	-	-	-	-	-	-	-	-	-	489
GIC's	60,058	-	21,323	20,449	-	37,179	7,398	22,626	-	58,847	-	227,880
Negotiable CD's	-	-	-	-	-	-	-	-	60	-	-	60
Commercial Paper	-	-	-	-	-	-	-	-	-	-	-	-
Equity Link Notes	-	-	-	-	-	-	-	-	-	-	-	-
Money Market Funds	1,626	126	615	1,512	182	2,290	571	747	3,665	8	2,852	14,194
Total	$ 258,977	$ 4,259	$ 51,193	$ 73,312	$ 1,597	$ 87,358	$ 13,715	$ 38,961	$ 30,730	$ 66,304	$ 79,852	$ 706,258
Restricted investments	$ 166,233	$ 2,255	$ 38,089	$ 45,363	$ -	$ 58,681	$ 7,399	$ 22,628	$ 64	$ 66,296	$ 69,969	$ 476,977
Unrestricted investments	78,263	1,278	-	-	-	-	-	-	-	-	-	79,541
Cash and cash equivalents	14,481	726	13,104	27,949	1,597	28,677	6,316	16,333	30,666	8	9,883	149,740
Total	$ 258,977	$ 4,259	$ 51,193	$ 73,312	$ 1,597	$ 87,358	$ 13,715	$ 38,961	$ 30,730	$ 66,304	$ 79,852	$ 706,258

	JUNE 30, 2006											
	GENERATION					TRANSMISSION			NATURAL GAS	MISCELLANEOUS		
	Palo Verde Project	Hoover Uprating Project	San Juan Project	Magnolia Power Project	Ormat Geo thermal Project	Southern Trans-mission System Project	Mead-Phoenix Project	Mead-Adelanto Project	Natural Gas Project	Multiple Project Fund	Projects' Stabiliza-tion Fund	Total
U.S. Agencies	$ 167,590	$ 2,152	$ 14,641	$ 19,423	$ 1,780	$ 995	$ -	$ -	$ -	$ -	$ 63,018	$ 269,599
Agency Discount Notes	6,580	1,964	12,047	29,877	-	40,326	5,162	14,647	10,721	-	1,088	122,412
Treasury Coupon	477	-	-	-	-	-	-	-	-	7,435	-	7,912
GIC's	64,584	-	21,323	-	-	37,180	8,095	22,990	-	57,960	-	212,132
Negotiable CD's	-	-	-	-	-	-	-	-	60	-	-	60
Commercial Paper	-	-	-	-	-	-	-	-	-	-	-	-
Equity Link Notes	4,452	-	-	-	-	-	-	-	-	-	-	4,452
Money Market Funds	1,823	51	1,772	3,095	564	9,309	311	845	2,951	-	1,987	22,708
Total	$ 245,506	$ 4,167	$ 49,783	$ 52,395	$ 2,344	$ 87,810	$ 13,568	$ 38,482	$ 13,732	$ 65,395	$ 66,093	$ 639,275
Restricted investments	$ 157,118	$ 2,813	$ 38,589	$ 26,241	$ 1,733	$ 71,204	$ 11,394	$ 33,939	$ 3,705	$ 65,395	$ 63,018	$ 475,149
Unrestricted investments	82,788	560	-	-	-	-	-	-	-	-	-	83,348
Cash and cash equivalents	5,600	794	11,194	26,154	611	16,606	2,174	4,543	10,027	-	3,075	80,778
Total	$ 245,506	$ 4,167	$ 49,783	$ 52,395	$ 2,344	$ 87,810	$ 13,568	$ 38,482	$ 13,732	$ 65,395	$ 66,093	$ 639,275

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.

Note 3 - Investments (Continued)

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, 2007 and June 30, 2006, each of the money market funds in the portfolio have attained the highest possible ratings by three NRSRO's, specifically AAA 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, 2007 and June 30, 2006, 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 Investors Service and AA by Fitch Ratings.

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 Investors 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 Investors Service, and A by Fitch Ratings.

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 Investors Service, and AAA by Fitch Ratings.

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, 2007, $269,001,768 (38%) was invested in securities issued by the Federal Home Loan Bank; $114,250,959 (16%) was invested in securities issued by the Federal National Mortgage Association; $80,506,618 (12%) was invested in an investment agreement with Financial Security Assurance (FSA); $88,871,134 (13%) was invested in a GIC with PNC Financial Securities Group; and $58,501,781 (8%) was invested in a GIC with American International Group (AIG).

Note 3 - Investments (Continued)

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 (14%) 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 GIC with PNC Financial Securities Group; and $62,953,499 (10%) was invested in a GIC with AIG.

Note 4 - Derivative Instruments

Objective of the swaps - An interest rate swap, is the exchange of payments between SCPPA and a counterparty in order to potentially obtain a lower cost of funding than traditional fixed rate bonds, or to hedge interest rate exposure on SCPPA's assets or liabilities. The Authority has entered into eight separate pay-fixed, receive-variable interest rate swaps and three basis swaps to produce savings or to result in lower costs over the life of each transaction than what the Authority would have paid to issue fixed-rate debt. While these instruments carry additional risks, SCPPA's swap policy and favorable negotiations have considered and helped to reduce such risks.

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, 2007, 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
MPP 2007 Swap	$ 111,630	6/13/2007	3.912%	98.9% of BMA less .06%	$ 3,056	7/1/2036	AAA/Aaa
MPP 2007 Swap	111,630	6/13/2007	3.912%	98.9% of BMA less .06%	3,056	7/1/2036	AAA/Aaa/AA+
MA 2007 Swap	100,000	2/1/2008	1-month LIBOR	100% of 10-yr LIBOR CMS rate less .414%	579	9/15/2030	AAA/Aaa
STS 2006 Amended Swap	100,000	8/1/2007	BMA	58.99% of 10-yr LIBOR CMS rate plus .664%	2,205	7/1/2023	AA/Aaa/AA-
STS 2004 Swap	100,000	12/1/2004	BMA	65% of LIBOR plus 0.664%	71	7/1/2023	AA/Aaa/AA-
MP 2004 Swap	28,700	5/27/2004	3.894%	65% of LIBOR	(569)	7/1/2020	AA+/Aa2/AA+
MA 2004 Swap	96,025	5/27/2004	3.890%	65% of LIBOR	(1,871)	7/1/2020	AA+/Aa2/AA+
STS 2003 Swap	50,500	4/24/2003	3.266%	65% of LIBOR	1,960	7/1/2022	AA/Aaa/AA+
STS Swaption/Swap	125,000	2/6/2001	4.250%	60% of LIBOR	(12,924)	7/1/2022	AA/Aaa/AA+
STS 2001 Swap	79,795	6/14/2001	4.240%	BMA less .40%	(5,427)	7/1/2021	AA+/Aa2/AA+
STS 1991 Swap	280,000	4/17/1991	6.380%	Bond variable coupon rate	(47,214)	6/30/2019	AA/Aa2/-
	$ 1,183,280				$ (57,078)		

Note 4 - Derivative Instruments (Continued)

- **MPP 2007 Swap** - In April 2007, the Authority entered into an interest rate swap in connection with the issuance of variable-rate Magnolia Power Project A, Refunding Revenue Bonds, Series 2007-1 ("2007-1 Bonds"). The Swap created synthetic fixed-rate debt. The transaction consisted of a $223,260,000 29-year floating-to-fixed interest rate swap allocated equally between two counterparties. The Authority pays each of the counterparties a fixed rate of 3.912% in exchange for receiving 98.9% of the BMA Index minus 6 basis points. The swap's effective date is June 13, 2007, with variable interest and swap payments commencing January 1, 2008. The swap expires on July 1, 2036.

- **MA 2007 Swap** - In January 2007, the Authority entered into a Constant Maturity Swap ("CMS") in connection with its outstanding Mead-Adelanto Project. The transaction consisted of a $100 million basis swap and does not relate to any single series of the Mead-Adelanto bonds. The swap terms will become effective on February 1, 2008 and under the swap, the Authority will pay the swap counterparty 100% of 1-month LIBOR in exchange for receiving 100% of the 10-year LIBOR minus 41.4 basis points. The swap expires on September 15, 2030.

- **STS 2006 Amended Swap** - In July 2006, the Authority executed an amendment to the STS $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 BMA index but will receive 58.99% of the 10-Year 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. The notional amount of the Swap Agreement remains at $100 million. The swap expires on July 1, 2023.

- **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. The term of this Swap was amended in July, 2006 and the amended terms will be effective on August 1, 2007. (See STS 2006 Interest Rate Amendment).

- **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, 2007 and 2006 was 3.50% and 3.80%, respectively.

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, 2007 and 2006 was 3.522% and 3.80%, respectively.

- **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, 2007 and 2006 was 3.70%. 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 counterparty has the option to cancel the agreement at the counterparty's discretion. The swap expires on July 1, 2022.

- **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 3.65% and 3.92% at June 30, 2007 and 2006, respectively. The swap expires on July 1, 2021.

Note 4 - Derivative Instruments (Continued)

- **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 (3.68% and 3.87% at June 30, 2007 and 2006, respectively). The swap expires on June 30, 2019.

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

Credit risk - As of June 30, 2007, the net fair values of the Authority's applicable swaps for which payments were made were negative for each counterparty except for the STS 2004 and the STS 2003 swaps. However, should interest rates change and the fair values of the swaps become positive, the Authority may be exposed to credit risk in the amount of the derivatives' fair value.

The swap agreements contain varying collateral agreements with the counterparties. The swaps require full collateralization of the fair value of the swap should the counterparty's (or 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; Baa1/BBB+ for the Swaption/Swap; and Baa3/BBB- for the Magnolia 2007 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 or variable swap rate the Authority pays on any related bonds or on any basis swap. The Authority is exposed to basis risk should the floating rate that it receives on a swap be less than the actual variable rate the Authority pays on any related bonds or in the case of the floating-to-floating fixed-spread basis swap, less than the variable rate paid to the swap counterparty.

Note 4 - Derivative Instruments (Continued)

Depending on the magnitude and duration of any basis risk shortfall, the expected cost savings from a swap may not be fully realized. For example, 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, 2007, the BMA rate, minus 40 bps, was 3.297%, whereas 60% of LIBOR was 3.192%, 65% of LIBOR was 3.458%, and 98.9% of BMA minus 6 bps, was 3.597%.

The following is a summary of interest rates paid to and received from the counterparties as of June 30, 2007:

	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%	3.704%	3.894%	3.890%
Less, variable payments from counterparty	3.680%	3.192%	3.297%	3.458%	3.458%	3.458%	3.458%
Net interest rate swap payments	2.700%	1.058%	0.943%	-0.192%	0.246%	0.436%	0.432%
Add, variable-rate bond coupon payments	3.680%	N/A	3.650%	3.700%	N/A	3.530%	3.530%
Synthetic interest rate on bonds	6.380%	1.058%	4.593%	3.508%	0.246%	3.966%	3.962%

Termination risk - The Authority or the counterparty may terminate any of the swaps if the other party fails to perform under the terms of the contract. In addition, the Swap/Swaption provides the counterparty with an option to cancel the swap agreement if the consecutive 180-day averaged rate of the BMA index exceeds 7.0%. The counterparty for the 2001 Swap also has a cancellation option which can be executed by the counterparty at their discretion. 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 Swap/Swaption and 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

Note 4 - Derivative Instruments (Continued)

Swap payments and associated debt - Using rates as of June 30, 2007, 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
2008	18,330	31,841	10,409	42,250
2009	19,770	31,119	9,980	41,099
2010	17,790	30,464	9,534	39,998
2011	18,910	29,768	9,058	38,826
2012 - 2016	272,660	120,874	32,560	153,434
2017 - 2021	300,000	64,605	9,743	74,348
2022 - 2026	68,975	36,777	3,013	39,790
2027 - 2031	60,420	25,481	2,184	27,665
2032 - 2036	113,350	11,474	983	12,457

Note 5 - Long-Term Debt

Long-term debt outstanding at June 30, 2007 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.

The Authority has agreed to certain covenants with respect to bonded indebtedness, including the requirement to enforce the natural gas, power and transmission sales agreements with the participants. At the option of the Authority, all outstanding new money bonds and refunding bonds are subject to redemption prior to maturity, except for the 2006-1 Magnolia Revenue Bonds; the 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.

Note 5 - Long-Term Debt (Continued)

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)									
	GENERATION			TRANSMISSION				NATURAL GAS	MISCELLANEOUS	
	Palo Verde Project	Hoover Uprating Project	San Juan Project	Magnolia Power Project	Southern Transmission System Project	Mead- Phoenix Project	Mead- Adelanto Project	Natural Gas Project	Multiple Project Fund	Total
Total long-term debt at June 30, 2006	$ 98,215	$ 16,821	$ 171,715	$ 316,740	$ 755,702	$ 63,154	$ 202,596	$ 28,200	$ 41,279	$ 1,694,422
Total debt due within one year at June 30, 2006	11,545	1,315	9,570	3,735	34,230	3,250	10,850	-	-	74,495
Total debt at June 30, 2006	109,760	18,136	181,285	320,475	789,932	66,404	213,446	28,200	41,279	1,768,917
Principal payments	(11,545)	(1,315)	(9,570)	(3,735)	(34,230)	(3,250)	(10,850)	-	-	(74,495)
Revenue bonds issued	-	-	-	37,730	-	-	-	44,900	-	82,630
Bonds refunded/defeased	-	-	-	(202,375)	-	-	-	-	-	(202,375)
Refunding bonds issued	-	-	-	223,260	-	-	-	-	-	223,260
Decrease in unamortized debt-related costs, net	2,053	428	(125)	(14,755)	10,889	536	1,513	-	1,274	1,813
Total debt at June 30, 2007	100,268	17,249	171,590	360,600	766,591	63,690	204,109	73,100	42,553	1,799,750
Total debt due within one year at June 30, 2007	(11,895)	(1,370)	(10,050)	(7,450)	(30,950)	(3,350)	(11,150)	(1,800)	-	(78,015)
Total long-term debt at June 30, 2007	$ 88,373	$ 15,879	$ 161,540	$ 353,150	$ 735,641	$ 60,340	$ 192,959	$ 71,300	$ 42,553	$ 1,721,735

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

Hoover Uprating Project - Debt consists of refunding series bonds with fixed interest rates between 4.0% and 5.25% and a final maturity during 2017.

San Juan Project - Debt consists of refunding series bonds with fixed interest rates between 5.0% 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 is being amortized in accordance with GASB 23, over the life of the new debt which is shorter than the remaining life of the old debt.

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.

Magnolia Power Project Refunding - In June 2007, the Authority issued $223.26 million of Magnolia Power Project Project A Refunding Revenue Bonds, 2007-1 Series as variable rate demand obligations that will initially bear interest at a weekly interest rate. The bonds were issued to refund $202.38 million of the Magnolia Power Project A Bonds, Revenue Series 2003 -1. The Authority also entered into two separate floating-to-fixed interest rate swap agreements allocated equally between two swap counterparties in connection with the Series 2007-1 Bonds which effectively fixed the rate of the 2007-1 Bonds. (See Note 4).

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.

Of the outstanding Magnolia Power Project Revenue Bonds, $14.0 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.

Southern Transmission System Project - Debt consists of refunding and subordinate refunding series bonds with fixed and variable interest rates. Fixed interest rates range from 3.00% to 6.38% and final maturities occur between 2011 and 2023.

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.

Natural Gas Projects
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. The bonds were issued on behalf of the Project A Participants to finance their share of the Natural Gas Projects. Additional draws may be used to increase the amount of natural gas to which the Natural Gas Project A Participants are entitled. As of June 30, 2007, the total draws were $28 million for the Pinedale Project, $45 million for the Barnett Project and the outstanding aggregate principal of the Draw Down Bonds was $73,100,100.

Note 5 - Long-Term Debt (Continued)

Multiple Project Fund - Debt consists of revenue bonds with fixed interest rate of 6.75% 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.

Debt Related Costs - Unamortized debt-related costs, net are as follows as of June 30, 2007 (amounts in thousands):

Unamortized debt-related costs, net	Loss on Refunding	(Premium) Discount	Total
Palo Verde Project	$ 13,447	$ -	$ 13,447
Southern Transmission System Project	88,455	19,075	107,530
Hoover Uprating Project	1,751	(230)	1,521
Mead-Phoenix Project	5,193	(229)	4,964
Mead-Adelanto Project	15,445	(1,235)	14,210
Multiple Project Fund	-	7,647	7,647
San Juan Project	5,524	(9,199)	(3,675)
Magnolia Power Project	13,262	(4,902)	8,360
Natural Gas Project	-	-	-
	$ 143,077	$ 10,927	$ 154,004

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, 2007 of 3.68% and 3.72%, respectively. The variable rates used for the MA and MP 2004 Subordinate Refunding Series A, and the STS 2000 and 2001 Subordinate Refunding Series A were the rates at June 30, 2007 of 3.50% and 3.65%, respectively. The variable rates used for the NGP 2005 Subordinate Refunding Series A, and the STS 2003 Subordinate Refunding Series A were the rates at June 30, 2007 of 5.32% and 3.70%, respectively. The variable rates are set by the bond-remarketing agent on a weekly basis based on economic conditions and bond ratings.

Note 5 - Long-Term Debt (Continued)

	GENERATION				TRANSMISSION			NATURAL GAS	MISCELLANEOUS	
	Palo Verde Project	Hoover Uprating Project	San Juan Project	Magnolia Power Project	Southern Trans-mission System Project	Mead-Phoenix Project	Mead-Adelanto Project	Natural Gas Projects	Multiple Project Fund	Total
2008 Principal	$ 11,895	$ 1,370	$ 10,050	$ 7,450	$ 30,950	$ 3,350	$ 11,150	$ 73,100	$ -	$ 149,315
2008 Interest	3,820	838	8,517	15,137	38,082	3,141	9,730	4,032	3,389	86,686
2009 Principal	12,250	1,425	10,550	7,930	31,550	3,425	11,400	-	-	78,530
2009 Interest	3,409	782	7,982	14,895	36,323	3,055	9,445	-	3,389	79,280
2010 Principal	10,075	1,480	11,115	8,615	30,880	3,500	11,725	-	-	77,390
2010 Interest	3,049	723	7,400	14,579	34,582	2,967	9,152	-	3,389	75,841
2011 Principal	10,375	1,540	11,715	8,930	33,115	4,560	12,540	-	11,400	94,175
2011 Interest	2,703	662	6,787	14,201	32,683	2,660	8,305	-	2,619	70,620
2012 Principal	10,685	1,600	12,345	9,310	35,780	4,840	13,310	-	12,100	99,970
2012 Interest	2,347	597	6,140	13,813	30,645	2,333	7,407	-	1,802	65,084
2013 - 2017 Principal	58,435	9,220	81,865	53,005	254,920	25,580	79,895	-	26,700	589,620
2013 - 2017 Interest	6,052	1,678	17,524	62,060	123,074	7,001	23,256	-	932	241,577
2018 - 2022 Principal	-	2,135	30,275	40,890	333,525	23,400	78,300	-	-	508,525
2018 - 2022 Interest	-	28	2,079	50,731	55,854	1,410	4,719	-	-	114,821
2023 - 2027 Principal	-	-	-	51,515	123,400	-	-	-	-	174,915
2023 - 2027 Interest	-	-	-	40,127	2,609	-	-	-	-	42,736
2028 - 2032 Principal	-	-	-	63,080	-	-	-	-	-	63,080
2028 - 2032 Interest	-	-	-	28,593	-	-	-	-	-	28,593
2033 - 2037 Principal	-	-	-	118,234	-	-	-	-	-	118,234
2033 - 2037 Interest	-	-	-	12,854	-	-	-	-	-	12,854
Principal	$ 113,715	$ 18,770	$ 167,915	$ 368,959	$ 874,120	$ 68,655	$ 218,320	$ 73,100	$ 50,200	$ 1,953,754
Interest	$ 21,380	$ 5,308	$ 56,429	$ 266,990	$ 353,852	$ 22,567	$ 72,014	$ 4,032	$ 15,520	$ 818,092

Fair Value - The fair value of the Authority's long-term debt (including the current portion) is approximately $1.9 billion and $2.0 billion at June 30, 2007 and 2006, 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.

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, 2007 and 2006, $880.1 million and $702.5 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, 2007, the remaining balance is $56 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, 2007, the remaining principal balance is $3.9 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.

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

	June 30, 2005	Fiscal Year 2006 Activity	June 30, 2006	Fiscal Year 2007 Activity	June 30, 2007
GAAP items not included in billings to participants					
Depreciation of plant	$ (921,907)	$ (65,433)	$ (987,340)	$ (67,586)	$ (1,054,926)
Nuclear fuel amortization	(19,548)	-	(19,548)	-	(19,548)
Decommissioning expense	(151,277)	(13,269)	(164,546)	(11,779)	(176,325)
Amortization of bond discount, debt issue costs, and loss on refundings	(635,328)	(17,877)	(653,205)	(16,800)	(670,005)
Interest expense	(71,076)	5,479	(65,597)	(2,065)	(67,662)
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	293,139	2,202	295,341	9,698	305,039
Costs of acquisition of capacity	17,434	(1,305)	16,129	(1,356)	14,773
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	911,918	70,212	982,130	78,593	1,060,723
Other	55,698	15,858	71,556	28,463	100,019
	(314,744)	(4,133)	(318,877)	17,168	(301,709)
Multiple Project Fund net assets	7,600	(1,848)	5,752	(1,768)	3,984
Projects' Stabilization Fund net assets	74,113	(7,520)	66,593	14,049	80,642
	$ (233,031)	$ (13,501)	$ (246,532)	$ 29,449	$ (217,083)

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. The public power systems in the Authority were not required to comply with the Bill's provisions. Most of the Authority's members have made investments in new gas-fired peaking or base-load generation located in Southern California. The price volatility of natural gas, which is the fuel source for many of California's electric generating units, may contribute to greater volatility in the Project Participants' revenues from the sale (and purchase) of electric energy and could materially affect the financial condition of the affected Project Participants. However, the gas supply and services to be provided by the Authority are intended to maintain and improve the competitive position of the Project Participants by providing them with additional services and very competitive prices for a portion of their gas supply.

Public Benefits - The members continue to collect the public benefit charge, and to date, have instituted in excess of $910 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 2.85% of gross revenues) have been spent on renewable resources, conservation, research and development, and low income rate subsidies.

Environmental Matters - Recent California legislation has addressed various issues affecting the utility industry including the need to generate electricity from renewable resources, the need to reduce greenhouse gases, improve air quality, and ensure clean water. In general, these bills provide for reduced greenhouse gas emission standards and greater investment in energy-efficient and environmentally friendly generation alternatives through more stringent renewable resource portfolio standards. The following is a brief summary of certain of these bills.

Greenhouse Gas Emissions - In its 2003 Integrated Energy Policy Report, the California State Energy Resources and Conservation and Development Commission (the "CEC") recommended that utilities account for the cost of greenhouse gas emission reductions in utility procurement decisions. Some of these mandates include, but are not limited to: Executive Order S-3-05, which placed an emphasis on such efforts to reduce greenhouse gas emissions by establishing statewide greenhouse gas reduction targets; Executive Order S-06-06 which directs the State to meet a 20% biomass utilization target within the renewable generation targets of 2010 and 2020 for the contribution to greenhouse gas emission reduction; Assembly Bill 32, the Global Warming Solutions Act of 2006 (the "GWSA") prescribed a statewide cap on global warming pollution with a goal of reaching 1990 greenhouse gas emission levels by 2020 and 80% below 1990 levels by 2050; Senate Bill 1368 provides for a restriction on the negotiation of contracts with potential baseload fossil fuel electric generating resources that exceed the rate of emissions for greenhouse gases for existing combined-cycle natural gas baseload generation and seeks to allow the CEC to establish a regulatory framework necessary to enforce the greenhouse gas emission performance standard for publicly-owned utilities, such as Anaheim; Assembly Bill 1925 provides for the CEC to develop a cost effective strategy for the geologic sequestration and management of industrial carbon dioxide; and Senate Bill 1686, which authorizes the Wildlife Conservation Board to take into account the potential of forestlands to beneficially reduce or sequester greenhouse gas emissions when it prioritizes funds available for proposed acquisitions. Some of these mandates also include additional requirements that may have additional significant financial implications.

Note 8 - Commitments and Contingencies (Continued)

Renewable Portfolio Standards (RPS) - Senate Bill 1078 ("SB 1078") directed the state's municipal utilities to implement and enforce an RPS that recognizes the intent of the Legislature to encourage development of renewable resources taking into consideration the impact on a utility's standard on rates, reliability, financial resources, and the goal of environmental improvement. Since the implementation of SB 1078, the California Public Utilities Commission and the State Energy Resources Conservation and Development Commission have taken a number of actions that have had an impact on the renewable energy goals set by legislation primarily seeking to accelerate the time line for meeting the renewable resource development goals and to provide additional standards for future extension of the goals. SCPPA is unable to determine what impact all of these factors will have on the energy markets or its participants.

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 2015. 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"). Due to a series of setbacks including scientific challenges by the Academy of Science, falsified research data by consultants, delays in submitting the construction application to the Nuclear Regulatory Commission, the DOE expected that the Yucca Mountain site would be open no earlier than 2015. However, the State of Nevada and its congressional delegation are still determined to halt the project through the NRC process or through legal challenges which could put the in-service date further in the future

A feud over a full and adequate funding and budget for the development of the repository between the administration and the Congressional leaders which comprise Nuclear opponents had further delayed the feasibility study and the submission of the construction application. 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.

Note 8 - Commitments and Contingencies (Continued)

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 54 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 2015, the spent fuel from PVNGS will be shipped to the repository starting in 2036. No provision has been included in the accompanying financial statements.

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 per incident for all 3 units, limited to payments of $2.7 million per incident, per year.

In addition to the above, the Authority may be subject to retroactive insurance assessments for its participation in the Neil 1 Property Insurance Program in the amount of $2,421,142.

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.

Note 8 - Commitments and Contingencies (Continued)

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 anticipated to begin to be added in January 2008. A current estimate which would be borne by the SCPPA San Juan Generating Station participants totals $32 million. Since 2005, SCPPA has 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.

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 case is currently in the discovery stage of litigation before the District Court for Millard County, Utah. No provision has been included in the accompanying financial statements.

Note 8 - Commitments and Contingencies (Continued)

Prior to the commencement of the construction of the Magnolia Power Project ("Project"), the Authority entered into an engineering, procurement and construction agreement (the "EPC Agreement") with Kvaerner E&C ("Kvaerner"), a division of Aker Kvaerner, which is headquartered in Oslo, Norway. Under the EPC Agreement, Kvaerner was responsible for the design, engineering procurement, construction, installation, training for operation, commissioning, start-up, testing and completion of the Project. The Operating Agent, the Authority and the Authority's outside legal counsel on this matter believed that the claim for additional compensation was substantially without merit and violated many provisions of the EPC Agreement. The matter went to mediation and in the mediation, in order to avoid further costly time consuming litigation, SCPPA offered to settle the matter for approximately $1.9 million which was an amount approximately equaling the amount of liquidated damages which, due the alleged delay in completion, had been withheld from Kvaerner at the conclusion of construction. The mediation of this matter, however, failed to settle the matter. In May 2007, Kvaerner filed a lawsuit against the Authority in California state court for damages for breach of contract and violation of the California prompt payment act. The appropriate California county for venue for this action is currently an issue which is being disputed between the parties. The action is currently in the pleading stage.

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.

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, 2007
(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, 2006	$ -	$ -	$ 138,040	$ -	$ -	$ 392,045	$ -	$ 2,428	$ 86,934	$ 24,239	$ -	$ 643,686
Additions												
Investment earnings	-	-	5,554	-	-	855	-	131	3,686	708	9	10,943
Discount on investment purchases	-	-	(201)	-	-	18,312	-	223	297	116	25	18,772
Distribution of investment earnings	-	-	-	-	-	-	-	(354)	(875)	(824)	2,053	-
Revenue from power sales	-	-	-	-	-	-	-	-	-	-	71,033	71,033
Distribution of revenue	-	-	-	-	-	-	-	16,972	42,473	13,674	(73,119)	-
Transfer from escrow fund for principal and interest payments	3,209	-	-	-	-	(54,215)	-	51,007	-	-	(1)	-
Total	3,209	-	5,353	-	-	(35,048)	-	67,979	45,581	13,674	-	100,748
Deductions												
Construction expenditures	-	-	-	-	-	-	-	-	-	9,827	-	9,827
Operating expenditures	-	-	3	-	-	-	-	-	33,658	-	-	33,661
Remarketing/commitment fees	-	-	-	-	-	-	-	272	-	-	-	272
Fuel costs	-	-	-	-	-	-	-	-	12,231	-	-	12,231
Payment of principal	-	-	-	-	-	-	-	11,545	-	-	-	11,545
Interest paid - non escrow	-	-	-	-	-	-	-	4,377	-	-	-	4,377
Premium and interest paid on investment purchases	-	-	(19)	-	-	-	-	-	-	-	-	- (19)
Payment of principal and interest paid escrow	3,209	-	-	-	-	-	-	51,007	-	-	-	54,216
Total	3,209	-	(16)	-	-	-	-	67,201	45,889	9,827	-	126,110
Balance at June 30, 2007	$ -	$ -	$ 143,409	$ -	$ -	$ 356,997	$ -	$ 3,206	$ 86,626	$ 28,086	$ -	$ 618,324

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 $101 and $78 held in the revolving fund at June 30, 2007 and 2006, 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, 2007
(AMOUNTS IN THOUSANDS)

	Debt Service Fund	General Reserve Fund	Advance Payment Fund	Operating Fund	Revenue Fund	Total
Balance at June 30, 2006	$ 1,213	$ 1,703	$ -	$ 1,316	$ -	$ 4,232
Additions						
Investment earnings	8	51	-	24	3	86
Discount on investment purchases	34	-	-	39	-	73
Distribution of investment earnings	(42)	(51)	-	(64)	157	-
Revenue from power sales	-	-	-	-	2,354	2,354
Distribution of revenue	2,213	-	-	301	(2,514)	-
Other	-	-	-	-	-	-
Total	2,213	-	-	300	-	2,513
Deductions						
Operating expenses	-	-	-	256	-	256
Payment of principal	1,315	-	-	-	-	1,315
Interest paid	906	-	-	-	-	906
Total	2,221	-	-	256	-	2,477
Balance at June 30, 2007	$ 1,205	$ 1,703	$ -	$ 1,360	$ -	$ 4,268

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 $21 and $16 held in the revolving fund at June 30, 2007 and 2006, respectively.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
SAN JUAN PROJECT
SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS IN FUNDS REQUIRED BY THE BOND INDENTURE FOR THE YEAR ENDED JUNE 30, 2007
(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, 2006	$ 4,625	$ 21,323	$ -	$ 6,062	$ 17,782	$ 31	$ (1)	$ 76,699	$ 126,521
Additions									
Investment earnings	6	1,101	21	6	539	1	-	3,123	4,797
Discount on investments	269	-	21	170	561	-	-	-	1,021
Distribution of investment earnings	(276)	(1,101)	2,654	(176)	(1,100)	(1)	-	-	-
Revenue from power sales	-	-	84,144	-	-	-	-	-	84,144
Distribution of revenues	18,579	-	(86,840)	46,162	22,099	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total	18,578	-	-	46,162	22,099	-	-	3,123	89,962
Deductions									
Operating expenses	-	-	-	48,343	-	-	-	-	48,343
Construction expenses	-	-	-	-	18,432	-	-	-	18,432
Payment of principlal and interest - escrow	-	-	-	-	-	-	-	3,772	3,772
Premium and interest on investment purchases	-	-	-	-	(11)	-	-	-	(11)
Payment of principal	9,570	-	-	-	-	-	-	-	9,570
Interest paid - non-escrow	9,247	-	-	-	-	-	-	-	9,247
Total	18,817	-	-	48,343	18,421	-	-	3,772	89,353
Balance at June 30, 2007	$ 4,386	$ 21,323	$ -	$ 3,881	$ 21,460	$ 31	$ (1)	$ 76,050	$ 127,130

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 $34 and $22 held in the revolving fund at June 30, 2007 and 2006, respectively.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
MAGNOLIA POWER PROJECT
SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS IN FUNDS REQUIRED BY THE BOND INDENTURE FOR THE YEAR ENDED JUNE 30, 2007
(AMOUNTS IN THOUSANDS)

	Debt Service Account	Debt Service Reserve Account	Project Fund	Operating Reserve Fund	Reserve and Contingency	Operating Fund	Revenue Fund	General Reserve Fund	Total
Balance at June 30, 2006	$ 11,322	$ 19,619	$ 1,646	$ 4,915	$ -	$ 14,865	$ -	$ -	$ 52,367
Additions									
Investment earnings	12	1,306	16	15	186	20	28	8	1,591
Discount on investment purchases	317	39	269	260	265	385	5	275	1,815
Distribution of investment earnings	(329)	(1,371)	-	(271)	(449)	(405)	2,868	(43)	-
Bond Proceeds 2006A	-	3,863	24,287	-	9,580	-	-	-	37,730
Bond Proceeds 2007A	-	16,586	1,951	-	-	-	-	-	18,537
Transfer of funds for debt service payment	(4,216)	(10,120)	-	-	-	-	-	-	(14,336)
Receipt from participants	-	-	-	-	-	-	63,939	-	63,939
Distribution of revenues	23,231	-	-	-	30	29,047	(55,048)	2,740	-
Transfer to Project Fund/General Reserve Fund	-	-	(2,824)	-	(20)	8,508	(11,792)	6,128	-
Other receipts	-	-	902	-	-	4	-	-	906
Total	19,015	10,303	24,601	4	9,592	37,559	-	9,108	110,182
Deductions									
Construction expenditures	-	-	2,594	-	-	-	-	-	2,594
Operating expenses	-	-	16,144	-	-	48,973	-	-	65,117
Interest paid	15,133	-	-	-	-	-	-	-	15,133
Premium and interest on investment purchases	704	-	-	-	38	-	-	-	742
Payment of principal	3,735	-	-	-	-	-	-	-	3,735
Debt issuance costs	-	-	2,128	-	-	-	-	-	2,128
Total	19,572	-	20,866	-	38	48,973	-	-	89,449
Balance at June 30, 2007	$ 10,765	$ 29,922	$ 5,381	$ 4,919	$ 9,554	$ 3,451	$ -	$ 9,108	$ 73,100

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 $31 and $14 held in the revolving fund at June 30, 2007 and 2006, 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, 2007
(AMOUNTS IN THOUSANDS)

	Debt Service Fund	Escrow Fund	General Reserve Fund	Issue Fund	Operating Fund	Revenue Fund	Total
Balance at June 30, 2006	$ 2,320	$ 6,535	$ -	$ 76,027	$ 1,074	$ -	$ 85,956
Additions							
Investment earnings	-	-	-	2,925	10	30	2,965
Discount on investment purchases	37	-	-	1,307	121	62	1,527
Distribution of investment earnings	(37)	-	-	(4,232)	(131)	4,400	-
Revenue from transmission sales	-	-	-	-	-	87,781	87,781
Distribution of revenue	-	-	-	71,620	20,653	(92,273)	-
Transfer from/to escrow fund required by refunding bonds issuance	6,535	(6,535)	-	-	-	-	-
Bond Proceeds	-	-	-	-	-	-	-
Total	6,535	(6,535)	-	71,620	20,653	-	92,273
Deductions							
Operating expenses	-	-	-	-	17,731	-	17,731
Payment of principal	8,855	-	-	25,375	-	-	34,230
Interest paid	-	-	-	39,328	-	-	39,328
Payment of principal and interest - escrow bonds	-	-	-	1,338	-	-	1,338
Other Disbursement	-	-	-	-	-	-	-
Total	8,855	-	-	66,041	17,731	-	92,627
Balance at June 30, 2007	$ -	$ -	$ -	$ 81,606	$ 3,996	$ -	$ 85,602

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 $52 and $34 held in the revolving fund at June 30, 2007 and 2006, respectively.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
MEAD-PHOENIX PROJECT
SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS IN FUNDS REQUIRED BY THE BOND INDENTURE FOR THE YEAR ENDED JUNE 30, 2007
(AMOUNTS IN THOUSANDS)

	Revenue Fund	Debt Service Account	Debt Service Reserve Account	Operating Fund	Reserve & Contingency Fund	Surplus Fund	Total
Balance at June 30, 2006	$ -	$ 4,934	$ 5,915	$ 279	$ 1,244	$ 1,112	$ 13,484
Additions							
Investment earnings	4	80	435	9	92	4	624
Discount on investment earnings	-	136	-	-	-	68	204
Distribution of investment earnings	203	405	(435)	(9)	(92)	(72)	-
Transmission revenue	7,209	-	-	-	-	-	7,209
Distribution of revenues	(7,583)	5,886	-	1,344	160	193	-
Payments from Western Area Power Administration	167	-	-	-	-	-	167
Other transfers	-	-	-	-	-	-	-
Total	-	6,507	-	1,344	160	193	8,204
Deductions							
Construction expenditures	-	-	-	-	156	-	156
Operating expenses	-	-	-	1,261	-	-	1,261
Principal payment	-	3,250	-	-	-	-	3,250
Interest paid	-	3,350	-	-	-	-	3,350
Total	-	6,600	-	1,261	156	-	8,017
Balance at June 30, 2007	$ -	$ 4,841	$ 5,915	$ 362	$ 1,248	$ 1,305	$ 13,671

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 $18 and $12 held in the revolving fund at June 30, 2007 and 2006, respectively.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
MEAD-ADELANTO PROJECT
SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS IN FUNDS REQUIRED BY THE BOND INDENTURE FOR THE YEAR ENDED JUNE 30, 2007
(AMOUNTS IN THOUSANDS)

	Debt Service Account	Debt Service Reserve Fund	Operating Fund	Reserve & Contingency	Revenue Fund	Surplus Fund	Total
Balance at June 30, 2006	$ 12,640	$ 16,267	$ 966	$ 6,383	$ -	$ 2,003	$ 38,259
Additions							
Investment earnings	49	1,196	8	469	9	5	1,736
Discount on investment earnings	387	-	33	-	-	112	532
Distribution of investment earnings	1,317	(1,196)	(41)	(469)	506	(117)	-
Transmission revenue	-	-	-	-	21,094	-	21,094
Distribution of revenues	20,593	-	1,164	-	(21,634)	(123)	-
Payment from Western Area Power Administration	-	-	-	-	25	-	25
Other transfers	-	-	-	-	-	-	-
Total	22,346	-	1,164	-	-	(123)	23,387
Deductions							
Principal payment	10,850	-	-	-	-	-	10,850
Interest paid	10,457	-	-	-	-	-	10,457
Operating expenses	-	-	1,485	-	-	-	1,485
Total	21,307	-	1,485	-	-	-	22,792
Balance at June 30, 2007	$ 13,679	$ 16,267	$ 645	$ 6,383	$ -	$ 1,880	$ 38,854

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 $18 and $10 held in the revolving fund at June 30, 2007 and 2006, respectively.

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, 2007
(AMOUNTS IN THOUSANDS)

	Proceeds Account	Debt Service Account	Earnings Account	Cost of Redemption Account	Total
Balance at June 30, 2006	$ 64,977	$ 418	$ -	$ -	$ 65,395
Additions					
Investment earnings	4,251	47	-	-	4,298
Distribution of investment earnings	(4,229)	-	4,229	-	-
Transfer for debt service payment	-	4,229	(4,229)	-	-
Transfer from debt service account	-	-	-	-	-
Total	22	4,276	-	-	4,298
Deductions					
Interest paid	-	3,389	-	-	3,389
Payment of principal	-	-	-	-	-
Redemption of bonds	-	-	-	-	-
Cost of redemption	-	-	-	-	-
Total	-	3,389	-	-	3,389
Balance at June 30, 2007	$ 64,999	$ 1,305	$ -	$ -	$ 66,304

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
NATURAL GAS (PINEDALE AND BARNETT) PROJECT
SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS IN FUNDS REQUIRED BY THE BOND INDENTURE FOR THE YEAR ENDED JUNE 30, 2007
(AMOUNTS IN THOUSANDS)

	Revenue Fund	Operating Fund	Debt Service Fund	General Reserve Fund	Project Fund	Capital Fund	Depository Fund	Total
Balance at June 30, 2006	$ -	$ 10,000	$ 508	$ -	$ 1,579	$ 1,609	$ -	$ 13,696
Additions								
Investment earnings	5	57	7	-	6	20	-	95
Discount on investment purchases	-	430	51	-	48	242	-	771
Distribution of investment earnings	-	3	-	-	-	(3)	-	-
Bond Proceeds 2005A	-	-	-	-	44,900	-	-	44,900
Other transfer	-	162	-	-	(149)	(13)	-	-
Receipt from participants	8,873	19,079	-	-	-	9,388	-	37,340
Other receipts	-	30,701	-	-	-	3,031	-	33,732
Distribution of revenues	(8,878)	(18,342)	5,814	-	(45,947)	67,353	-	-
Total	-	32,090	5,872	-	(1,142)	80,018	-	116,838
Deductions								
Construction expenditures	-	-	-	-	28	65,844	-	65,872
Operating expenses	-	31,078	-	-	-	-	-	31,078
Interest paid	-	-	2,978	-	-	-	-	2,978
Total	-	31,078	2,978	-	28	65,844	-	99,928
Balance at June 30, 2007	$ -	$ 11,012	$ 3,402	$ -	$ 409	$ 15,783	$ -	$ 30,606

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 $24 and $14 held in the revolving fund at June 30, 2007 and 2006, respectively.

El Paso Electric

Jeffrey T. Weikert
Assistant General Counsel

P.O. Box 982
El Paso, Texas
79960-0982
(915) 543-5711

July 2, 2008

United States Nuclear Regulatory Commission
Attention Document Control Desk
Mail Station P1-37
Washington, D.C. 20555-0001

Subject: Docket Nos. STN50-528/529/530
Submission of El Paso Electric Company Form 10-K Annual Report for the fiscal year ended December 31, 2007, Certified 2008 Cash Flow Projection, and Application for Withholding Information from Public Disclosure

Dear Ladies and Gentlemen:

In accordance with 10 C.F.R. § 140.21(e), enclosed for submission to the United States Nuclear Regulatory Commission ("NRC") are the following documents:

1. Form 10-K Annual Report of El Paso Electric Company ("EPE") for the fiscal year ended December 31, 2007;

2. EPE's certified 2008 Cash Flow Projection marked "Confidential and Proprietary Commercial and Financial Information Submitted Under 10 U.S.C. § 2.390"; and

3. Application to the NRC pursuant to 10 C.F.R. § 2.390, including the Affidavit of Mr. Steven P. Busser, Vice President, Treasurer, and Chief Risk Officer of EPE, requesting that EPE's certified 2008 Cash Flow Projection be withheld from public disclosure.

To maintain its confidentiality, the Statement was delivered to Arizona Public Service Company ("APS"), the operating agent of the Palo Verde Nuclear Generating Station ("Palo Verde"), along with the Form 10-K and Application in a sealed envelope addressed to the NRC. By agreement, APS is forwarding the sealed envelope for submission to the NRC along with the projected cash flow statements of APS and the other Palo Verde participants. Please contact the undersigned if the seal of the EPE envelope is broken prior to your receipt.

Your assistance with this matter is appreciated in advance. If you have any questions or comments concerning this matter, please let me know.

Sincerely,

Jeffrey T. Weikert

cc: Mr. Stan Michaelis
Mr. Steven P. Busser
Mr. Wayne Soza
Mr. Juan M. Azcarate III

El Paso Electric

Jeffrey T. Weikert
Assistant General Counsel

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Mr. Steven P. Busser
Mr. Wayne Soza
Mr. Juan M. Azcarate III

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El Paso Electric

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Mr. Steven P. Busser
Mr. Wayne Soza
Mr. Juan M. Azcarate III

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2007

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from ____ to ____

Commission file number 0-296

El Paso Electric Company

(Exact name of registrant as specified in its charter)

Texas	**74-0607870**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
Stanton Tower, 100 North Stanton, El Paso, Texas	**79901**
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: **(915) 543-5711**

Securities Registered Pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, No Par Value	**New York Stock Exchange**

Securities Registered Pursuant to Section 12(g) of the Act:
None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
YES _X_ NO ___

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.
YES ____ NO _X_

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

YES _X_ NO ___

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [X]

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company (as defined in Rule 12b-2 of the Act).

Large accelerated filer _X_ Accelerated filer ____ Non-accelerated filer ____ Smaller reporting company ____

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act).

YES ___ NO _X_

As of June 30, 2007, the aggregate market value of the voting stock held by non-affiliates of the registrant was $1,109,228,847 (based on the closing price as quoted on the New York Stock Exchange on that date).

As of January 31, 2008, there were 45,150,655 shares of the Company's no par value common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's definitive Proxy Statement for the 2008 annual meeting of its shareholders are incorporated by reference into Part III of this report.

DEFINITIONS

The following abbreviations, acronyms or defined terms used in this report are defined below:

Abbreviations, Acronyms or Defined Terms	Terms
2007 New Mexico Stipulation	Stipulation in Case No. 06-00258-UT dated February 6, 2007, between the Company and other parties to the Company's rate proceeding before the NMPRC
ANPP Participation Agreement	Arizona Nuclear Power Project Participation Agreement dated August 23, 1973, as amended
APS	Arizona Public Service Company
CFE	Comisión Federal de Electricidad de Mexico, the national electric utility of Mexico
Common Plant or Common Facilities	Facilities at or related to Palo Verde that are common to all three Palo Verde units
Company	El Paso Electric Company
DOE	United States Department of Energy
El Paso	City of El Paso, Texas
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Fort Bliss	The United States Army Air Defense Center located in El Paso, Texas
Four Corners	Four Corners Generating Station
kV	Kilovolt(s)
kW	Kilowatt(s)
kWh	Kilowatt-hour(s)
Las Cruces	City of Las Cruces, New Mexico
MW	Megawatt(s)
MWh	Megawatt-hour(s)
NMPRC	New Mexico Public Regulation Commission
Net dependable generating capability	The maximum load net of plant operating requirements which a generating plant can supply under specified conditions for a given time interval, without exceeding approved limits of temperature and stress
New Mexico Restructuring Act	New Mexico Electric Utility Industry Restructuring Act of 1999
NRC	Nuclear Regulatory Commission
Palo Verde	Palo Verde Nuclear Generating Station
Palo Verde Participants	Those utilities who share in power and energy entitlements, and bear certain allocated costs, with respect to Palo Verde pursuant to the ANPP Participation Agreement
PNM	Public Service Company of New Mexico
SFAS	Statement of Financial Accounting Standards
SPS	Southwestern Public Service Company
TEP	Tucson Electric Power Company
Texas Commission	Public Utility Commission of Texas
Texas Freeze Period	Five-year period beginning July 1, 2005, during which base rates for most Texas retail customers remain frozen pursuant to the City Rate Agreement
Texas Restructuring Law	Texas Public Utility Regulatory Act Chapter 39, Restructuring of the Texas Electric Utility Industry
TNP	Texas-New Mexico Power Company

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FORWARD-LOOKING STATEMENTS

Certain matters discussed in this Annual Report on Form 10-K other than statements of historical information are "forward-looking statements." The Private Securities Litigation Reform Act of 1995 has established that these statements qualify for safe harbors from liability. Forward-looking statements may include words like we "believe", "anticipate", "target", "expect", "pro forma", "estimate", "intend" and words of similar meaning. Forward-looking statements describe our future plans, objectives, expectations or goals. Such statements address future events and conditions concerning and include, but are not limited to such things as:

- capital expenditures,
- earnings,
- liquidity and capital resources,
- litigation,
- accounting matters,
- possible corporate restructurings, acquisitions and dispositions,
- compliance with debt and other restrictive covenants,
- interest rates and dividends,
- environmental matters,
- nuclear operations, and
- the overall economy of our service area.

These forward-looking statements involve known and unknown risks that may cause our actual results in future periods to differ materially from those expressed in any forward-looking statement. Factors that would cause or contribute to such differences include, but are not limited to, such things as:

- our rates in Texas following the end of the Texas Freeze Period,
- our rates in New Mexico following the 2007 New Mexico Stipulation,
- loss of margins on off-system sales due to changes in wholesale power prices or availability of competitive generation resources,
- ability of our operating partners to maintain plant operations and manage operation and maintenance costs at Palo Verde and Four Corners plants including additional costs associated with the degraded cornerstone status of Palo Verde,
- reductions in output at generation plants operated by the Company,
- unscheduled outages including outages at Palo Verde,
- electric utility deregulation or re-regulation,
- regulated and competitive markets,
- ongoing municipal, state and federal activities,
- economic and capital market conditions,
- changes in accounting requirements and other accounting matters,
- changing weather trends,
- rates, cost recoveries and other regulatory matters including the ability to recover fuel costs on a timely basis,
- changes in environmental regulations,
- political, legislative, judicial and regulatory developments,

- the impact of lawsuits filed against us,
- the impact of changes in interest rates,
- changes in, and the assumptions used for, pension and other post-retirement and post-employment benefit liability calculations, as well as actual and assumed investment returns on pension plan assets,
- the impact of changing cost escalation and other assumptions on our nuclear decommissioning liability for the Palo Verde Nuclear Generating Station,
- Texas, New Mexico and electric industry utility service reliability standards,
- homeland security considerations,
- coal, uranium, natural gas, oil and wholesale electricity prices and availability, and
- other circumstances affecting anticipated operations, sales and costs.

These lists are not all-inclusive because it is not possible to predict all factors. A discussion of some of these factors is included in this document under the headings "Risk Factors" and "Management's Discussion and Analysis" "–Summary of Critical Accounting Policies and Estimates" and "–Liquidity and Capital Resources." This report should be read in its entirety. No one section of this report deals with all aspects of the subject matter. Any forward-looking statement speaks only as of the date such statement was made, and we are not obligated to update any forward-looking statement to reflect events or circumstances after the date on which such statement was made except as required by applicable laws or regulations.

PART I

Item 1. Business

General

El Paso Electric Company is a public utility engaged in the generation, transmission and distribution of electricity in an area of approximately 10,000 square miles in west Texas and southern New Mexico. The Company also serves a wholesale customer in Texas and from time to time a customer in the Republic of Mexico. The Company owns or has significant ownership interests in six electrical generating facilities providing it with a net dependable generating capability of approximately 1,503 MW. For the year ended December 31, 2007, the Company's energy sources consisted of approximately 43% nuclear fuel, 28% natural gas, 7% coal, 22% purchased power and less than 1% generated by wind turbines.

The Company serves approximately 360,000 residential, commercial, industrial and wholesale customers. The Company distributes electricity to retail customers principally in El Paso, Texas and Las Cruces, New Mexico (representing approximately 55% and 9%, respectively, of the Company's operating revenues for the year ended December 31, 2007). In addition, the Company's wholesale sales include sales for resale to other electric utilities and power marketers. Principal industrial and other large customers of the Company include United States military installations, including Fort Bliss in Texas and White Sands Missile Range and Holloman Air Force Base in New Mexico, two large universities, and oil, copper refining and steel production facilities.

The Company's principal offices are located at the Stanton Tower, 100 North Stanton, El Paso, Texas 79901 (telephone 915-543-5711). The Company was incorporated in Texas in 1901. As of January 31, 2008, the Company had approximately 1,000 employees, 44% of whom are covered by a collective bargaining agreement.

The Company makes available free of charge through its website, www.epelectric.com, its annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and all amendments to those reports as soon as reasonably practicable after such material is electronically filed with or furnished to the Securities and Exchange Commission ("SEC"). In addition, copies of the annual report will be made available free of charge upon written request. The SEC also maintains an internet site that contains reports, proxy and information statements and other information for issuers that file electronically with the SEC. The address of that site is www.sec.gov. The information on the internet site is not incorporated into this document by reference.

Facilities

The Company's net dependable generating capability of 1,503 MW consists of the following:

Station	Primary Fuel Type	Net Dependable Generating Capability (MW)
Palo Verde Station	Nuclear Fuel	633
Newman Power Station	Natural Gas	474
Rio Grande Power Station	Natural Gas	229
Four Corners Station	Coal	104
Copper Power Station	Natural Gas	62
Hueco Mountain Wind Ranch	Wind	1
Total		1,503

Palo Verde Station

The Company owns a 15.8% interest in each of the three nuclear generating units and Common Facilities at Palo Verde, in Wintersburg, Arizona. The Palo Verde Participants include the Company and six other utilities: APS, Southern California Edison Company ("SCE"), PNM, Southern California Public Power Authority, Salt River Project Agricultural Improvement and Power District ("SRP") and the Los Angeles Department of Water and Power. APS serves as operating agent for Palo Verde, and under the ANPP Participation Agreement, the Company has limited ability to influence operations and costs at Palo Verde.

The NRC has granted facility operating licenses and full power operating licenses for Palo Verde Units 1, 2 and 3, which expire in 2024, 2025 and 2027, respectively. In addition, the Company is separately licensed by the NRC to own its proportionate share of Palo Verde.

Pursuant to the ANPP Participation Agreement, the Palo Verde Participants share costs and generating entitlements in the same proportion as their percentage interests in the generating units, and each participant is required to fund its share of fuel, other operations, maintenance and capital costs. The ANPP Participation Agreement provides that if a participant fails to meet its payment obligations, each non-defaulting participant shall pay its proportionate share of the payments owed by the defaulting participant.

NRC. The NRC regulates the operation of all commercial nuclear power reactors in the United States, including Palo Verde. The NRC periodically conducts inspections of nuclear facilities and monitors performance indicators to enable the agency to arrive at objective conclusions about a licensee's safety performance. Based on this assessment information and using a cornerstone evaluation system, the NRC determines the appropriate level of agency response and oversight, including supplemental inspections and pertinent regulatory actions as necessary.

In October 2006, the NRC conducted an inspection of the Palo Verde emergency diesel generators after a Palo Verde Unit 3 emergency diesel generator did not activate during routine inspections in July and September 2006. On February 22, 2007, the NRC issued a "white" finding (low to moderate safety significance) for this matter. Based upon this finding, coupled with a previous NRC "yellow" finding (substantial safety significance) relating to a 2004 matter involving Palo Verde's safety

injection systems, the NRC placed Palo Verde Unit 3 in the "multiple/repetitive degraded cornerstone" column of the NRC's action matrix which has resulted in an enhanced NRC inspection regimen. This enhanced inspection regimen and resulting corrective actions has resulted in increased operating costs at the plant. Of the 104 commercial nuclear reactors in the United States regulated by the NRC, only Palo Verde Unit 3 was listed in the "multiple/repetitive degraded cornerstone" category as of the end of 2007. The Company is currently unable to predict the impact that the NRC's increased oversight may have on Palo Verde's operations and the cost of operations.

Decommissioning. Pursuant to the ANPP Participation Agreement and federal law, the Company must fund its share of the estimated costs to decommission Palo Verde Units 1, 2 and 3, including the Common Facilities, through the term of their respective operating licenses. The Company is required to maintain a minimum accumulation and a minimum funding level in its decommissioning account at the end of each annual reporting period during the life of the plant. The Company has established external trusts with an independent trustee which enable the Company to record a current deduction for federal income tax purposes of a portion of amounts funded. At December 31, 2007, the Company's decommissioning trust fund had a balance of $130.7 million and the Company was above its minimum funding level. The Company will continue to monitor the status of its decommissioning funds and adjust its deposits, if necessary, to remain at or above its minimum accumulation requirements in the future.

Decommissioning costs are estimated every three years based upon engineering cost studies performed by outside engineers retained by APS. In 2005, the Palo Verde Participants approved the 2004 Palo Verde decommissioning study ("2004 Study"). The 2004 Study estimated that the Company must fund approximately $335.7 million (stated in 2004 dollars) to cover its share of decommissioning costs. Although the 2004 Study was based on the latest available information, there can be no assurance that decommissioning cost estimates will not increase in the future or that regulatory requirements will not change. In addition, until a new low-level radioactive waste repository opens and operates for a number of years, estimates of the cost to dispose of low-level radioactive waste are subject to significant uncertainty. A study of decommissioning costs was performed in 2007 ("2007 Study"). Preliminary results of the 2007 Study indicate a reduction in decommissioning costs from the 2004 Study which, if adopted, will result in lower asset retirement obligations and lower expenses in the future. The 2007 Study is expected to be approved in the second quarter of 2008. See "Spent Fuel Storage" and "Disposal of Low-Level Radioactive Waste" below.

Spent Fuel Storage. The original spent fuel storage facilities at Palo Verde had sufficient capacity to store all fuel discharged from normal operation of all three Palo Verde units through 2003. Alternative on-site storage facilities and casks have been constructed to supplement the original facilities. In March 2003, APS began removing spent fuel from the original facilities as necessary, and placing it in special storage casks which will be stored at the new facilities until accepted by the DOE for permanent disposal. The 2004 Study assumed that costs to store fuel on-site will become the responsibility of the DOE after 2037. APS believes that spent fuel storage or disposal methods will be available to allow each Palo Verde unit to continue to operate through the term of its operating license.

Pursuant to the Nuclear Waste Policy Act of 1982, as amended in 1987 (the "Waste Act"), the DOE is legally obligated to accept and dispose of all spent nuclear fuel and other high-level radioactive waste generated by all domestic power reactors. In accordance with the Waste Act, the DOE entered into a spent nuclear fuel contract with the Company and all other Palo Verde Participants. The DOE has previously reported that its spent nuclear fuel disposal facilities would not be in operation in the near future. Subsequent judicial decisions required the DOE to start accepting spent nuclear fuel by

January 31, 1998. The DOE did not meet that deadline, and the Company cannot currently predict when spent fuel shipments to the DOE's permanent disposal site will commence.

The Company expects to incur significant costs for on-site spent fuel storage during the life of Palo Verde that the Company believes are the responsibility of the DOE. These costs are assigned to fuel requiring the additional on-site storage and amortized as that fuel is burned until an agreement is reached with the DOE for recovery of these costs. In December 2003, APS, in conjunction with other nuclear plant operators, filed suit against the DOE on behalf of the Palo Verde Participants to recover monetary damages associated with the delay in the DOE's acceptance of spent fuel. On February 28, 2007, APS served on the U.S. Department of Justice its "Initial Disclosure of Claimed Damages" of $93.4 million (the Company's portion being $14.8 million). This amount includes expenses associated with design, construction, loading, and operation of the Palo Verde independent spent fuel storage installation through December 2006. This amount represents costs incurred to ensure sufficient storage capacity for Palo Verde spent fuel that would not have been incurred had the DOE complied with its standard contract obligation to begin accepting spent fuel from the commercial nuclear power industry beginning in 1998. The Company is unable to predict the outcome of this matter at this time.

Disposal of Low-Level Radioactive Waste. Congress has established requirements for the disposal by each state of low-level radioactive waste generated within its borders. Arizona, California, North Dakota and South Dakota have entered into a compact (the "Southwestern Compact") for the disposal of low-level radioactive waste. California will act as the first host state of the Southwestern Compact, and Arizona will serve as the second host state. The construction and opening of the California low-level radioactive waste disposal site in Ward Valley has been delayed due to extensive public hearings, disputes over environmental issues and review of technical issues related to the proposed site. Palo Verde is projected to undergo decommissioning during the period in which Arizona will act as host for the Southwestern Compact. The opposition, delays, uncertainty and costs experienced in California demonstrate possible roadblocks that may be encountered when Arizona seeks to open its own waste repository. APS currently believes that interim low-level waste storage methods are or will be available to allow each Palo Verde unit to continue to operate and to store safely low-level waste until a permanent disposal facility is available.

Reactor Vessel Heads. In accordance with applicable NRC requirements, APS conducts regular inspections of reactor vessel heads at Palo Verde Units 1, 2 and 3. In an effort to reduce long-term operating costs at the station related to inspection of the reactor heads, related equipment, and possible repair costs, APS plans to replace reactor vessel heads at Palo Verde. Reactor vessel head replacement is scheduled to occur at Units 1, 2 and 3 in 2010, 2009 and 2009, respectively. The Company's share of the costs for this project is estimated to be $21.3 million.

Liability and Insurance Matters. The Palo Verde participants have insurance for public liability resulting from nuclear energy hazards to the full limit of liability under federal law currently at $10.8 billion. This potential liability is covered by primary liability insurance provided by commercial insurance carriers in the amount of $300 million and the balance by an industry-wide retrospective assessment program. If a loss at a nuclear power plant covered by the programs exceeds the accumulated funds in the primary level of protection, the Company could be assessed retrospective premium adjustments on a per incident basis. Under federal law, the maximum assessment per reactor under the program for each nuclear incident is approximately $100.6 million, subject to an annual limit of $15 million. Based upon the Company's 15.8% interest in the three Palo Verde units, the Company's maximum potential assessment per incident for all three units is approximately $47.7 million, with an annual payment limitation of approximately $7.1 million.

The Palo Verde Participants maintain "all risk" (including nuclear hazards) insurance for property damage to, and decontamination of, property at Palo Verde in the aggregate amount of $2.75 billion, a substantial portion of which must first be applied to stabilization and decontamination. The Company has also secured insurance against portions of any increased cost of generation or purchased power and business interruption resulting from a sudden and unforeseen outage of any of the three units. The insurance coverage discussed in this and the previous paragraph is subject to certain policy conditions and exclusions. A mutual insurance company whose members are utilities with nuclear facilities issues these policies. If losses at any nuclear facility covered by this mutual insurance company were to exceed the accumulated funds for these insurance programs, the Company could be assessed retrospective premium adjustments of up to $11.5 million for the current policy period.

Newman Power Station

The Company's Newman Power Station, located in El Paso, Texas, consists of three steam-electric generating units and one combined cycle generating unit with an aggregate net capability of approximately 474 MW. The units operate primarily on natural gas but can also operate on fuel oil.

Rio Grande Power Station

The Company's Rio Grande Power Station, located in Sunland Park, New Mexico, adjacent to El Paso, Texas, consists of three steam-electric generating units with an aggregate net capability of approximately 229 MW. The units operate primarily on natural gas but can also operate on fuel oil.

Four Corners Station

The Company owns a 7% interest, or approximately 104 MW, in Units 4 and 5 at Four Corners, located in northwestern New Mexico. Each of the two coal-fired generating units has a total net capability of 739 MW. The Company shares power entitlements and certain allocated costs of the two units with APS (the Four Corners operating agent) and the other participants, PNM, TEP, SCE and SRP.

Four Corners is located on land under easements from the federal government and a lease from the Navajo Nation that expires in 2016, with a one-time option to extend the term for an additional 25 years. Certain of the facilities associated with Four Corners, including transmission lines and almost all of the contracted coal sources, are also located on Navajo land. Units 4 and 5 are located adjacent to a surface-mined supply of coal.

Copper Power Station

The Company's Copper Power Station, located in El Paso, Texas, consists of a 62 MW combustion turbine used primarily to meet peak demands. The unit operates primarily on natural gas but can also operate on fuel oil.

Hueco Mountain Wind Ranch

The Company's Hueco Mountain Wind Ranch, located in Hudspeth County, east of El Paso County and adjacent to Horizon City, currently consists of two wind turbines with a total capacity of 1.32 MW of which a portion, currently 28%, can be used as net capability for resource planning purposes.

Transmission and Distribution Lines and Agreements

The Company owns or has significant ownership interests in four major 345 kV transmission lines in New Mexico, three 500 kV lines in Arizona, and owns the transmission and distribution network within its New Mexico and Texas retail service area and operates these facilities under franchise agreements with various municipalities. The Company is also a party to various transmission and power exchange agreements that, together with its owned transmission lines, enable the Company to deliver its energy entitlements from its remote generation sources at Palo Verde and Four Corners to its service area. Pursuant to standards established by the North American Electric Reliability Corporation (formerly the North American Electric Reliability Council) and the Western Electricity Coordinating Council, the Company operates its transmission system in a way that allows it to maintain system integrity in the event that any one of these transmission lines is out of service.

Springerville-Luna-Diablo Line. The Company owns a 310-mile, 345 kV transmission line from TEP's Springerville Generating Plant near Springerville, Arizona, to the Luna Substation near Deming, New Mexico, and to the Diablo Substation near Sunland Park, New Mexico. This transmission line provides an interconnection with TEP for delivery of the Company's generation entitlements from Palo Verde and, if necessary, Four Corners.

West Mesa-Arroyo Line. The Company owns a 202-mile, 345 kV transmission line from PNM's West Mesa Substation located near Albuquerque, New Mexico, to the Arroyo Substation located near Las Cruces, New Mexico. This is the primary delivery point for the Company's generation entitlement from Four Corners, which is transmitted to the West Mesa Substation over approximately 150 miles of transmission lines owned by PNM.

Greenlee-Hidalgo-Luna-Newman Line. The Company owns 40% of a 60-mile, 345 kV transmission line between TEP's Greenlee Substation near Duncan, Arizona to the Hidalgo Substation near Lordsburg, New Mexico, approximately 57% of a 50-mile, 345 kV transmission line between the Hidalgo Substation and the Luna Substation and 100% of an 86-mile, 345 kV transmission line between the Luna Substation and the Newman Power Station. These lines provide an interconnection with TEP for delivery of the Company's entitlements from Palo Verde and, if necessary, Four Corners. The Company owns the Afton 345 kV Substation located approximately 57 miles from the Luna Substation on the Luna-to-Newman portion of the line. The Afton Substation interconnects a generator owned and operated by PNM.

Eddy County-AMRAD Line. The Company owns 66.7% of a 125-mile, 345 kV transmission line from the Company's and PNM's (formerly TNP's) high voltage direct current terminal at the Eddy County Substation near Artesia, New Mexico to the AMRAD Substation near Oro Grande, New Mexico. The Company owns 66.7% of the terminal. This terminal enables the Company to connect its transmission system to that of SPS (a subsidiary of Xcel Energy), providing the Company with access to purchased and emergency power from SPS and power markets to the east.

Palo Verde Transmission and Switchyard. The Company owns 18.7% of two 45-mile, 500 kV lines from Palo Verde to the Westwing Substation located northwest of Phoenix near Peoria, Arizona and 18.7% of a 75-mile, 500 kV line from Palo Verde to the Jojoba Substation, then to the Kyrene Substation located near Tempe, Arizona. These lines provide the Company with a transmission path for delivery of power from Palo Verde. The Company also owns 18.7% of two 500 kV switchyards connected to the Palo Verde-Kyrene 500 kV line: the Hassayampa switchyard adjacent to the southern edge of the Palo Verde 500 kV switchyard and the Jojoba switchyard approximately 24 miles from

Palo Verde. These switchyards were built to accommodate the addition of new generation and transmission in the Palo Verde area.

Environmental Matters

The Company is subject to regulation with respect to air, soil and water quality, solid waste disposal and other environmental matters by federal, state, tribal and local authorities. Those authorities govern current facility operations and have continuing jurisdiction over facility modifications. Failure to comply with these environmental regulatory requirements can result in actions by regulatory agencies or other authorities that might seek to impose on the Company administrative, civil, and/or criminal penalties. In addition, unauthorized releases of pollutants or contaminants into the environment can result in costly cleanup obligations that are subject to enforcement by regulatory agencies.

These laws and regulations are subject to change and, as a result of those changes, the Company may face additional capital and operating costs to comply. For example, recent developments suggest a growing likelihood of future regulation relating to climate change and greenhouse gas emissions. At the federal level, Congress continues to hold many hearings relating to climate change issues and many bills have been introduced to impose regulation through regulatory schemes including a "cap and trade" program. The United States Supreme Court has found carbon dioxide, one of the principal greenhouse gases, to be a "pollutant" under the Clean Air Act, increasing the possibility that the U.S. Environmental Protection Agency will begin to regulate these emissions even in the absence of further action by Congress. In addition, the State of New Mexico, where the Company operates one facility and has an interest in another facility, has joined with California and several other states in the Western Regional Climate Action Initiative and is pursuing initiatives to reduce greenhouse gas emissions in the state. The Company is monitoring these developments and how regulation may affect it. If the United States or individual states in which the Company operates were to regulate greenhouse gas emissions, the Company's fossil fuel generation assets are likely to face additional costs for monitoring, reporting, controlling, or offsetting these emissions.

Another way in which environmental matters may impact the Company's operations and business is the implementation of the U.S. Environmental Protection Agency's Clean Air Interstate Rule which, as applied to the Company, may result in a requirement that it substantially reduce emissions of nitrogen oxides from its power plants in Texas and/or purchase allowances representing other parties' emissions reductions starting in 2009. These requirements become more stringent in 2015, and are anticipated to require even further emissions reductions or additional allowance purchases.

The Company takes these regulatory matters seriously and is monitoring these issues so that the Company is best able to effectively adapt to any such changes. Because the Company's generating portfolio has a carbon footprint that compares favorably with other power generating companies, the Company believes such regulations would not impose greater relative burdens on the Company than on most other electric utilities. Environmental regulations like these can change rapidly and those changes are often difficult to predict. While the Company strives to prepare for and implement actions necessary to comply with changing environmental regulations, substantial expenditures may be required for the Company to comply with such regulations in the future and, in some instances, those expenditures may be material. The Company believes it is impossible at present to meaningfully quantify the costs of these potential impacts.

The Company analyzes the costs of its obligations arising from environmental matters on an ongoing basis and believes it has made adequate provision in its financial statements to meet such obligations. As a result of this analysis, the Company has a provision for environmental remediation obligations of approximately $1.4 million as of December 31, 2007, which amounts are related to compliance with federal and state environmental standards. However, unforeseen expenses associated with environmental compliance or remediation may occur and could have a material adverse effect on the future operations and financial condition of the Company.

Along with many other companies, the Company received from the Texas Commission on Environmental Quality ("TCEQ") a request for information in 2003 in connection with environmental conditions at a facility in San Angelo, Texas that was operated by the San Angelo Electric Service Company ("SESCO"). In November 2005, TCEQ proposed the SESCO site for listing on the registry of Texas state superfund sites and mailed notice to more than five hundred entities, including the Company, indicating that TCEQ considers each of them to be "potentially responsible parties" at the SESCO site. The Company received from the SESCO working group of potentially responsible parties a settlement offer in May 2006 for remediation and other expenses expected to be incurred in connection with the SESCO site. The Company's position is that any liability it may have related to the SESCO site was discharged in the Company's bankruptcy. At this time, the Company has not agreed to a settlement or to otherwise participate in the cleanup of the SESCO site and is unable to predict the outcome of this matter. While the Company has no reason at present to believe that it will incur material liabilities in connection with the SESCO site, it has accrued $0.3 million for potential costs related to this matter.

On September 26, 2006, the Secretary of the New Mexico Environment Department issued a Compliance Order concerning the Company's Rio Grande Generating Station, located in Dona Ana County, New Mexico. The Compliance Order alleges that, on approximately 650 occasions between May 2000 and September 2005, the Rio Grande Generating Station emitted sulfur dioxide, nitrogen oxides or carbon monoxide in excess of its permitted emission rates and failed to properly report these allegedly excess emissions. The Compliance Order asserts a statutory authority to seek a civil penalty of up to $15,000 per violation for each of the violations alleged. The Company disputes the allegations made and has requested a hearing before the New Mexico Environment Department on the matter. While the Company cannot predict the outcome of this matter, it believes these emissions did not violate applicable legal standards and that penalties, if any, should not involve a material liability.

On April 4, 2007, the Company submitted its application for a New Source Review Air Quality Permit/Prevention of Significant Deterioration ("PSD") permit to the TCEQ for the new natural-gas electric generating units to be located at its existing Newman plant site in the City of El Paso ("Newman Unit 5"). The Company expects to receive approval of its PSD application in the second quarter of 2008. Additional environmental permits other than the PSD are not required to begin construction of these new generating units because Newman Unit 5 will be constructed at an existing plant site and other permits are currently in place which will encompass Newman Unit 5.

In May 2007, the Environmental Protection Agency finalized a new federal implementation plan which addresses emissions at the Four Corners Station in northwestern New Mexico of which the Company owns a 7% interest in Units 4 and 5. Arizona Public Service, the Four Corners operating agent, has filed suit against the Environmental Protection Agency relating to this new federal implementation plan in order to resolve issues involving operating flexibility for emission opacity standards. The Company cannot predict the outcome of the suit filed against the Environmental

Protection Agency or whether compliance with the new requirements could have an adverse effect on its capital and operating costs.

Except as described herein, the Company is not aware of any other active investigation of its compliance with environmental requirements by the Environmental Protection Agency, the TCEQ or the New Mexico Environment Department which is expected to result in any material liability. Furthermore, except as described herein, the Company is not aware of any unresolved, potentially material liability it would face pursuant to the Comprehensive Environmental Response, Comprehensive Liability Act of 1980, also known as the Superfund law.

Construction Program

Utility construction expenditures reflected in the following table consist primarily of local generation, expanding and updating the transmission and distribution systems, including growth associated with the expansion of Ft. Bliss, and the cost of capital improvements and replacements at Palo Verde. Studies indicate that the Company will need additional power generation resources to meet increasing load requirements on its system, the costs of which are included in the table below.

The Company's estimated cash construction costs for 2008 through 2011 are approximately $842 million. Actual costs may vary from the construction program estimates shown. Such estimates are reviewed and updated periodically to reflect changed conditions.

By Year (1)(2) (In millions)		By Function (In millions)	
2008	$ 210	Production (1)(2)	$ 430
2009	219	Transmission	94
2010	213	Distribution	213
2011	200	General	105
Total	$ 842	Total	$ 842

(1) Does not include acquisition costs for nuclear fuel. See "Energy Sources – Nuclear Fuel."

(2) Includes $193 million for new gas-fired generating capacity and $60 million for other local generation, $18 million for the Four Corners Station and $159 million for the Palo Verde Station.

Energy Sources

General

The following table summarizes the percentage contribution of nuclear fuel, natural gas, coal and purchased power to the total kWh energy mix of the Company. Energy generated by wind turbines accounted for less than 1% of the total kWh energy mix.

Power Source	Years Ended December 31, 2007	2006	2005
Nuclear fuel	43%	42%	46%
Natural gas	28	25	30
Coal	7	9	9
Purchased power	22	24	15
Total	100%	100%	100%

Allocated fuel and purchased power costs are generally recoverable from customers in Texas and New Mexico pursuant to applicable regulations. Historical fuel costs and revenues are reconciled periodically in proceedings before the Texas Commission and the NMPRC. See "Regulation – Texas Regulatory Matters" and "– New Mexico Regulatory Matters."

Nuclear Fuel

The nuclear fuel cycle for Palo Verde consists of the following stages: the mining and milling of uranium ore to produce uranium concentrates; the conversion of the uranium concentrates to uranium hexafluoride ("conversion services"); the enrichment of uranium hexafluoride ("enrichment services"); the fabrication of fuel assemblies ("fabrication services"); the utilization of the fuel assemblies in the reactors; and the storage and disposal of the spent fuel. The Palo Verde Participants have contracts in place that will furnish 100% of Palo Verde's operational requirements for uranium concentrates, conversion services and enrichment services through 2008. Such contracts could also provide 100% of enrichment services in 2009 and 2010. The Palo Verde Participants have a contract that will provide 100% of fabrication services until at least 2015 for each Palo Verde unit.

Nuclear Fuel Financing. Pursuant to the ANPP Participation Agreement, the Company owns an undivided interest in nuclear fuel purchased in connection with Palo Verde. The nuclear fuel material market has recently been affected by supply disruptions and significant price increases with the cost of uranium having increased significantly in the last few years. The Palo Verde Participants have taken steps to mitigate the effects of future supply disruptions and price increases by changing from a procurement strategy under which nuclear fuel arrives at Palo Verde one month prior to being loaded into a reactor to a strategy where (i) nuclear fuel arrives on site three months before being loaded and (ii) a strategic inventory of converted nuclear fuel material sufficient to provide feed stock for one full reactor reload is stored for future use. This change in procurement strategy increased our cash funding requirements in 2007. In July 2007, the Company expanded its revolving credit facility from $150 million to $200 million which provides for both working capital and up to $120 million for the financing of nuclear fuel. This facility has a five-year term ending April 11, 2011. At December 31, 2007, approximately $83.0 million had been drawn to finance nuclear fuel. This financing is accomplished through a trust that borrows under the credit facility to acquire and process the nuclear fuel. The Company is obligated to repay the trust's borrowings with interest. In the Company's

financial statements, the assets and liabilities of the trust are consolidated and reported as assets and liabilities of the Company.

Natural Gas

The Company manages its natural gas requirements through a combination of a long-term supply contract and spot market purchases. The long-term supply contract provides for firm deliveries of gas at market-based index prices. In 2007, the Company's natural gas requirements at the Newman and Rio Grande Power Stations were met with both short-term and long-term natural gas purchases from various suppliers and this practice is expected to continue in 2008. Interstate gas is delivered under a base firm transportation contract. The Company anticipates it will continue to purchase natural gas at spot market prices on a monthly basis for a portion of the fuel needs for the Newman and Rio Grande Power Station. The Company will continue to evaluate the availability of short-term natural gas supplies versus long-term supplies to maintain a reliable and economical supply for the Newman and Rio Grande Power Stations.

Natural gas for the Newman and Copper Power Stations is also supplied pursuant to an intrastate natural gas contract that expired in 2007, but was extended on a short-term basis until a new contract can be negotiated. The Company is currently in the process of renegotiating this contract.

Coal

APS, as operating agent for Four Corners, purchases Four Corners' coal requirements from a supplier with a long-term lease of coal reserves owned by the Navajo Nation. The Four Corners coal contract expires in 2016 which coincides with the term of the Four Corners Plant lease with the Navajo Nation. Based upon information from APS, the Company believes that Four Corners has sufficient reserves of coal to meet the plant's operational requirements for its useful life.

Purchased Power

To supplement its own generation and operating reserves, the Company engages in firm and non-firm power purchase arrangements which may vary in duration and amount based on evaluation of the Company's resource needs and the economics of the transactions. In 2004, the Company entered into a 20-year contract, beginning in 2006, for the purchase of up to 133 MW of capacity and associated energy from SPS. This contract includes a demand charge, fuel charge, variable operations and maintenance charge, and a transmission charge. The contract provides that, in the event the transactions thereunder are subject to adverse regulatory action, the affected party may initiate discussions with the other party to assess whether modifications to the agreement may be appropriate. If the parties are unable to reach a mutually satisfactory resolution within six months, either party may terminate the contract by providing not less than two years' prior written notice to the other party.

The Company previously received notice from SPS that SPS had been subject to adverse regulatory action by the Texas Commission regarding transactions under the contract and that SPS wished to exercise its right to terminate the contract early. As a result, on January 29, 2008, the Company and SPS entered into an amendment to the contract and agreed that the contract will terminate on September 30, 2009.

In June 2006, the Company began exchanging up to 100 MW of capacity and associated energy with Phelps Dodge Energy. The contract provides for Phelps Dodge to deliver energy to the Company from its ownership interest in the Luna Energy Facility, an approximate 570 MW natural gas fired combined cycle generation facility located in Luna County, New Mexico and for the Company to deliver a like amount of energy at the Greenlee delivery point. The Company may purchase up to 100 MW at a specified price at times when energy is not exchanged. The agreement was approved by the FERC and continues through December 31, 2021.

Other purchases of shorter duration were made during 2007 primarily to replace the Company's generation resources during planned and unplanned outages and for economic reasons.

Operating Statistics

	Years Ended December 31,		
	2007	2006	2005
Operating revenues (in thousands):			
Non-fuel base revenues:			
Retail:			
Residential	$ 184,562	$ 175,641	$ 173,007
Commercial and industrial, small	168,091	161,359	158,406
Commercial and industrial, large	39,092	40,502	39,192
Sales to public authorities	72,763	68,438	65,861
Total retail base revenues	464,508	445,940	436,466
Wholesale:			
Sales for resale	1,919	1,794	1,687
Total non-fuel base revenues	466,427	447,734	438,153
Fuel revenues:			
Recovered from customers during the period	197,383	225,441	164,500
Under (over) collection of fuel	17,828	(3,655)	79,539
New Mexico fuel in base rates	51,487	30,033	29,440
Total fuel revenues	266,698	251,819	273,479
Off-system sales	125,974	95,932	78,209
Other	18,328	20,970	14,072
Total operating revenues	$ 877,427	$ 816,455	$ 803,913
Number of customers (end of year):			
Residential	317,091	311,923	304,031
Commercial and industrial, small	35,147	32,950	31,969
Commercial and industrial, large	53	58	61
Other	4,853	4,800	4,792
Total	357,144	349,731	340,853
Average annual kWh use per residential customer	7,085	6,852	6,936
Energy supplied, net, kWh (in thousands):			
Generated	7,707,095	6,908,006	7,500,144
Purchased and interchanged	2,188,904	2,208,661	1,255,626
Total	9,895,999	9,116,667	8,755,770
Energy sales, kWh (in thousands):			
Retail:			
Residential	2,232,668	2,113,733	2,090,098
Commercial and industrial, small	2,216,428	2,159,599	2,126,918
Commercial and industrial, large	1,195,038	1,204,707	1,165,506
Sales to public authorities	1,384,380	1,343,129	1,270,116
Total retail	7,028,514	6,821,168	6,652,638
Wholesale:			
Sales for resale	48,290	45,397	41,883
Off-system sales	2,201,294	1,635,407	1,420,778
Total wholesale	2,249,584	1,680,804	1,462,661
Total energy sales	9,278,098	8,501,972	8,115,299
Losses and Company use	617,901	614,695	640,471
Total	9,895,999	9,116,667	8,755,770
Native system:			
Peak load, kW	1,508,000	1,428,000	1,376,000
Net dependable generating capability for peak, kW (1)	1,492,000	1,492,000	1,479,000
Total system:			
Peak load, kW (2)	1,680,000	1,675,000	1,628,000
Net dependable generating capability for peak, kW (1) (3)	1,492,000	1,492,000	1,479,000
System capacity factor (4)	65.2%	59.7%	58.6%

(1) Excludes 11,000 kW increase in generating capability at Palo Verde related to the steam generator replacements for Unit 3 that was completed January 2008.
(2) Includes spot firm sales and net losses of 172,000 kW, 247,000 kW and 252,000 kW for 2007, 2006 and 2005, respectively.
(3) Excludes 133,000 kW for 2007 and 2006 and 103,000 kW for 2005 of firm on and off-peak purchases.
(4) System capacity factor includes average firm system purchases of 133,000 kW for 2007 and 2006 and 103,000 kW for 2005.

Regulation

General

The rates and services of the Company are regulated by incorporated municipalities in Texas, the Texas Commission, the NMPRC, and the FERC. The Texas Commission and the NMPRC have jurisdiction to review municipal orders, ordinances, and utility agreements regarding rates and services within their respective states and over certain other activities of the Company. The FERC has jurisdiction over the Company's wholesale transactions. The decisions of the Texas Commission, NMPRC and the FERC are subject to judicial review.

Texas Regulatory Matters

Texas Rate Agreements. The Company has entered into agreements ("Texas Rate Agreements") with El Paso, Commission Staff and other parties in Texas that provide for most retail base rates to remain at their current level through June 30, 2010. During the rate freeze period, if the Company's return on equity falls below the bottom of a defined range, the Company has the right to initiate a rate case and seek an adjustment to base rates. If the Company's return on equity exceeds the top of the range, the Company will refund an amount equal to 50% of the pretax return in excess of the ceiling. The range is based upon a risk premium above a twelve month average of comparable credit quality bond yields and at a twelve month average of such bond yields the range would be approximately 8.3% to 12.3%. During 2007 the Company's return on equity fell within this range.

Pursuant to a rate agreement with El Paso in July 2005, the Company agreed to share with its Texas customers 25% of off-system sales margins and wheeling revenues among other provisions. Under the prior rate agreement, the Company shared 50% of off-system sales margins and wheeling revenues with Texas customers. A request for approval of the off-system sales and wheeling revenue sharing provision was filed with the Texas Commission in January 2006 ("PUC Docket No. 32289").

In PUC Docket No. 32289, the Company entered into settlement agreements with the Texas Commission Staff, a large industrial customer, El Paso, Texas Ratepayers Organization to Save Energy, and the Office of the Attorney General of the State of Texas (the "State") which (i) extended the rate freeze to all customers in Texas; (ii) extended the earnings sharing provisions to all customers in Texas; (iii) expanded the Company's support of low-income energy efficiency programs; and (iv) provided that after the expiration of the Texas Rate Agreements, the Company will treat wheeling revenues and expenses associated with non-native load in a manner consistent with then-existing Texas Commission rules and other substantive and procedural law. In addition, the agreement with the State provides for the Company to share 90% of off-system sales margins with customers after June 30, 2010 through June 30, 2015. This provision is not binding on the Texas Commission or other settling parties. In addition, the Company agreed that upon the expiration of the rate freeze, it would file a full base rate case with the Texas Commission and the applicable cities having original jurisdiction if requested to do so by the Texas Commission staff, El Paso, the State or the Texas Office of Public Utility Counsel. The Company also retained the right to voluntarily file a full base rate case. The Company currently anticipates that it will need base rate relief in that time frame. On December 8, 2006, the Texas Commission approved the margin sharing provisions of the Texas Rate Agreements in PUC Docket No. 32289 pursuant to the settlement agreements.

Fuel and Purchased Power Costs. Although the Company's base rates are frozen under the Texas Rate Agreements, pursuant to Texas Commission rules and the Texas Rate Agreements, the Company's fuel costs including purchased power energy costs are recoverable from its customers. In January and July of each year, the Company can request adjustments to its fixed fuel factor to more accurately reflect projected energy costs associated with providing electricity, seek recovery of past undercollections of fuel revenues, and refund past overcollections of fuel revenues. All such fuel revenue and expense activities are subject to periodic final review by the Texas Commission in fuel reconciliation proceedings.

On August 31, 2007, the Company filed for authority to reconcile its eligible fuel expenses and revenues for the period of March 1, 2004 through February 28, 2007 ("Reconciliation Period"), which was assigned PUC Docket No. 34695. The Company is seeking to reconcile a total of $548.4 million in eligible fuel, fuel-related, and purchased power expenses to generate and purchase electric energy for its Texas retail customers. At the conclusion of the Reconciliation Period, the Company had a cumulative under-recovery of such expenses of $18.2 million of which $17.6 million was subject to an existing fuel surcharge. The Company is seeking to carry over the cumulative Reconciliation Period fuel under-recovery balance into the subsequent reconciliation period beginning March 2007. Hearings on the fuel reconciliation are scheduled in May 2008. A final order is not expected to be issued until the third quarter of 2008.

On January 8, 2008, the Company filed a request with the Texas Commission to surcharge approximately $30.1 million of under-recovered fuel and purchased power costs and interest over a twelve month period beginning in March 2008. The fuel under-recoveries were incurred during the period December 2005 through November 2007. A decision from the Texas Commission is expected in the first quarter of 2008.

On January 5, 2006, the Company filed a petition ("PUC Docket No. 32240") with the Texas Commission to increase its fixed fuel factors and to surcharge under-recovered fuel costs. The Company requested an increase in its Texas jurisdiction fixed fuel factors of $30.8 million or 16% annually to reflect an average cost of natural gas of $9.35 per MMBtu. The Company also requested a fuel surcharge to recover over a twelve-month period approximately $34 million of fuel undercollections, including interest, for under-recoveries for the period September 2005 through November 2005. The requested fuel factor and fuel surcharge were placed into effect on an interim basis subject to refund effective with February 2006 bills to customers. This proceeding was abated pending the Texas Commission's decision in the margin sharing proceeding, PUC Docket No. 32289, which was approved December 8, 2006. The Company filed a unanimous settlement with the Texas Commission to resolve all issues in this docket on January 24, 2007. The settlement provided for approval of the fuel surcharge and fuel factor for the period February 2006 through January 2007, the end of the surcharge period. In addition, the Company agreed to reduce its fixed fuel factors by 10% effective February 1, 2007 reducing annual fuel recoveries by approximately $20.0 million per year. The revised fixed fuel factors reflect natural gas prices of approximately $7.80 per MMBtu. A final order approving the settlement in PUC Docket No. 32240 was issued by the Texas Commission on March 15, 2007.

Generation CCN Filing. On July 6, 2007, the Company filed a petition with the Texas Commission requesting a Certificate of Convenience and Necessity ("CCN") for two generating facilities in PUC Docket No. 34494. The first such facility is a natural-gas fueled power generating unit to be located at an existing plant site in El Paso. This facility is known as Newman Unit 5. The Newman Unit 5 project consists of 280 to 290 MW of natural gas-fired combined cycle generating capacity that the Company presently plans to construct in two phases. The first phase includes two 70 MW gas turbines to be installed by the peak of 2009. The second phase converts the unit into a combined cycle combustion turbine with a total capacity of 280 to 290 MW and is expected to be completed by late 2010 or early 2011.

The Newman Unit 5 will operate mostly in a baseload manner, but can also be used in a load following manner. It will be the most efficient gas-fired unit on the Company's system when operated in combined cycle. The total estimated cost of the project including allowance for funds used during construction is $245 million.

The Company also requested a CCN for two renewable energy wind turbines currently operating at the Hueco Mountains Wind Ranch, the acquisition of which the Texas Commission had previously found to be consistent with the public interest.

On December 17, 2007, the parties to PUC Docket No. 34494 filed a Stipulation, signed by all parties, which recommended approval of the Company's requests. On January 31, 2008, the Texas Commission issued an order approving the requested CCNs. The costs of the project have not been approved.

Palo Verde Performance Standards. The Texas Commission established performance standards for the operation of Palo Verde pursuant to which each Palo Verde unit is evaluated annually to determine whether its three-year rolling average capacity factor entitles the Company to a reward or subjects it to a penalty. The capacity factor is calculated as the ratio of actual generation to maximum possible generation. If the capacity factor, as measured on a station-wide basis for any consecutive 36-month period, should fall below 52.5%, the parties to the Texas Rate Agreements can seek different rate treatment for Palo Verde. The removal of Palo Verde from rate base could have a significant negative impact on the Company's revenues and financial condition. The Company has calculated the performance rewards for the reporting periods ending in 2007 and 2006 to be approximately $0.6 million and $0.4 million, respectively. The 2006 reward was included along with energy costs incurred and fuel revenue billed as part of the Texas Commission's review during the 2007 fuel reconciliation proceeding as discussed above. Under the performance standards the Company did not earn a performance reward nor incur a penalty for the 2005 reporting period. Performance rewards are not recorded on the Company's books until the Texas Commission has ordered a final determination in a fuel proceeding or comparable evidence of collectibility is obtained. Performance penalties would be recorded when assessed as probable by the Company.

In a prior fuel reconciliation proceeding ("PUC Docket No. 20450"), the Company agreed to contribute any Palo Verde rewards in its next fuel reconciliation to assist low-income customers in paying their utility bills. In compliance with the Texas Commission's order, the Company sought and received approval by the El Paso City Council in January 2006 to remit to El Paso approximately $5.8 million in Palo Verde performance reward funds to fund demand side management programs such

as weatherization with a focus on programs to assist small business and commercial customers. As of December 31, 2007 $5.6 million, including accrued interest, remains to be paid under these agreements and is recorded as a liability on the Company's balance sheet.

Deregulation. The Texas Restructuring Law required certain investor-owned electric utilities to separate power generation activities and retail service activities from transmission and distribution activities by January 1, 2002, and on that date, retail competition for generation services was instituted in some parts of Texas. However, the Texas Commission has delayed retail competition in the Company's Texas service territory by approving a rule which identifies various milestones for the Company to reach before competition can begin. The first milestone calls for the development, approval by the FERC, and commencement of independent operation of a regional transmission organization (RTO) in the area that includes the Company's service territory, including the development of retail market protocols to facilitate retail competition (see "FERC Regulatory Matters – RTO" below). The complete transition to retail competition would occur upon the completion of the last milestone, which would be the Texas Commission's final evaluation of the market's readiness to offer fair competition and reliable service to all retail customers. The Company believes this rule delays retail competition in El Paso indefinitely. There is substantial uncertainty about both the regulatory framework and market conditions that will exist if and when retail competition is implemented in the Company's service territory, and the Company may incur substantial preparatory, restructuring and other costs that may not ultimately be recoverable. There can be no assurance that deregulation would not adversely affect the future operations, cash flows and financial condition of the Company.

Renewable Energy Requirements. Notwithstanding the Texas Commission's approval of a rule further delaying competition in the Company's Texas service territory, the Company became subject to the renewable energy and energy efficiency requirements of the Texas Restructuring Law on January 1, 2006. Under the renewable energy requirements, the Company is required to annually obtain its pro rata share of renewable energy credits as determined by the Program Administrator (the Electric Reliability Council of Texas). The Company's ultimate obligation to obtain renewable energy credits will not be known until January 31 of the year following the compliance year, and it will have until March 31 to obtain, if necessary, and submit to the Program Administrator, sufficient credits. The Company obtained the required renewable energy credits to meet its expected obligations through 2007.

2007 Energy Efficiency Legislation. New energy efficiency legislation was approved in Texas in June 2007. The new legislation establishes new and increased goals for additional cost-effective energy efficiency for residential and commercial customers equivalent to at least (i) 10% of the annual growth in peak demand for residential and commercial customers by December 31, 2007; (ii) 15% of the annual growth in demand by December 31, 2008; and (iii) 20% of the annual growth in demand by December 31, 2009. Among other things, the new legislation requires the Texas Commission to establish an energy efficiency cost recovery factor for ensuring cost recovery for utility expenditures made to satisfy the energy efficiency goal. The legislation provides that utilities that are unable to establish an energy efficiency cost recovery factor in a timely manner due to a rate freeze will be allowed to defer the costs of complying with the energy efficiency goal and recover such deferred costs at the end of the rate freeze period.

New Mexico Regulatory Matters

2007 New Mexico Stipulation. On July 3, 2007, the NMPRC issued a final order approving a stipulation ("2007 New Mexico Stipulation") addressing all issues in the 2006 rate filing in Case No. 06-00258-UT. On July 26, 2007, the NMPRC modified its final order to clarify that its approval of the Stipulation did not preclude the NMPRC from examining the Company's rates upon its own motion at any time prior to the date stipulated for the Company's next rate filing. The 2007 New Mexico Stipulation provides for a $5.8 million non-fuel base rate increase and a $0.3 million fuel and purchased power decrease relative to test year rates. The 2007 New Mexico Stipulation reflects average natural gas costs of $7.20 per MMBtu for the June 2007 through May 2008 forecast period. Most of the Company's fuel and purchased power costs during the period of the 2007 New Mexico Stipulation are expected to be recovered through base rates. Any difference between actual fuel and purchased power costs and the amount included in base rates will be recovered or refunded through the Fuel and Purchased Power Cost Adjustment Clause ("FPPCAC"). Rates will continue in effect until changed by the NMPRC after the Company's next rate case. The 2007 New Mexico Stipulation requires the Company to file its next general rate case no later than May 30, 2009 using a base period of the twelve months ending December 31, 2008. Under NMPRC statutes, new rates would become effective no later than June 2010.

The 2007 New Mexico Stipulation provides for energy from the deregulated Palo Verde Unit 3 to be recovered through fuel and purchased power costs based upon the contract cost of capacity and fuel for power purchased under the existing SPS purchased power contract. The 2007 New Mexico Stipulation eliminates the fixed fuel and purchased power cost of $0.021 per kWh for 10% of New Mexico kWh sales and requires 25% of jurisdictional off-system sales margins to be credited to customers through the FPPCAC. Consistent with the Texas settlement in PUC Docket No. 32289, beginning in July 2010 through June 2015, the Company will credit 90% of the New Mexico jurisdictional portion of off-system sales margins to New Mexico customers through the FPPCAC. No later than two years after implementation, the 2007 New Mexico Stipulation requires the Company to file to continue its FPPCAC according to NMPRC rules, at which time any party may propose to change the price of capacity and related energy from Palo Verde Unit 3 since the SPS purchased power contract will terminate in September 2009. The 2007 New Mexico Stipulation results in final reconciliation of fuel and purchased power costs for the period May 31, 2004 through December 31, 2005. The Company will continue to file annual reconciliation statements for fuel and purchased power costs in accordance with NMPRC rules. The Company filed a reconciliation statement for the period June 1, 2006 through May 31, 2007 on August 31, 2007.

Fuel and Purchased Power Costs. The Company currently recovers fuel and purchased power costs in base rates in an average amount of $0.04288 per kWh and recovers the remaining fuel and purchased power costs through its FPPCAC. See discussion of 2007 New Mexico Stipulation above.

Notice of Investigation of Rates. On August 3, 2007, the Company received by mail a "Notice of Investigation of Rates of El Paso Electric Company" from the NMPRC in Case No. 07-00317-UT (the "Notice"). On August 21, 2007, the NMPRC requested the Company to file a response to the issues, including the reasonableness of fuel and purchased power costs. On September 7, 2007, the Company filed its response and requested that the NMPRC suspend its investigation and close the docket. No further

action has been taken by the Commission. The Company is unable at this time to predict any potential negative financial impact from this docket.

Renewables. The New Mexico Renewable Energy Act of 2004 as amended by the 2007 New Mexico legislature requires that, by January 1, 2006, renewable energy comprise no less than 5% of the Company's total retail sales to New Mexico customers. This requirement has been fixed at 6% until January 1, 2011, when the renewable portfolio standard increases to 10% of the Company's total retail sales to New Mexico customers. After 2011, the renewable portfolio standard, as a percentage of total retail sales to New Mexico customers, increases to 15% by 2015 and 20% by 2020. The Company has met all requirements to date.

The NMPRC approved the Company's 2006 annual procurement plan ("Procurement Plan") in December 2006, including the purchase of renewable energy certificates ("RECs") and the issuance of a diversity RFP for renewable resources to meet future requirements. In addition, the NMPRC authorized the Company to enter into two 20-year purchased power agreements to purchase energy from an 8 MW low-emissions biomass generating facility and from a 6 kW solar energy generating facility. Both generating facilities would have been located within the Company's New Mexico service area. The biomass renewable supplier defaulted on its contract obligations. In the Order approving the 2006 Plan, the NMPRC approved recovery of REC costs, without associated energy, through the FPPCAC. The NMPRC's decision to allow recovery of REC costs, without associated energy, through the FPPCAC was appealed to the New Mexico Supreme Court (the "Court") by the New Mexico Industrial Energy Consumers. The Court issued a decision on August 28, 2007, ordering that RECs without associated energy could not be recovered through the FPPCAC, but the costs would be recovered through the ratemaking process. The Company filed a request to create a deferral as provided under New Mexico law, with carrying costs, to recover these costs and refunded to customers the previously-collected REC costs recovered through the FPPCAC. NMPRC action to approve the deferral, with carrying costs, is pending.

The Company filed its 2007 annual Procurement Plan on August 31, 2007. The Company has proposed procurement of Texas RECs to complete its 2008 and 2009 renewable obligations. The Company also requested funding to conduct a proposal process in 2008 to attempt to procure diverse renewable energy resources to meet NMPRC requirements. The Company is seeking a deferral of the costs associated with renewable compliance, including carrying costs. Hearings were held on November 29, 2007. The Hearing Examiner issued the Recommended Decision on December 5, 2007 recommending that the Company's request to replace the biomass project with Texas RECs be rejected and that the Company include a plan to replace these RECs with New Mexico RECs in its next procurement plan filing. The Company filed exceptions to the Recommended Decision on December 14, 2007. A NMPRC order adopting the Recommended Decision was issued on February 27, 2008.

New Mexico Energy Efficiency Plan Filing. On November 5, 2007, the Company filed its Application for Approval of Energy Efficiency and Load Management Programs. This case has been designated as NMPRC Case No. 07-00411-UT. In this filing, the Company requests approval of a number of energy efficiency programs. The Company also proposed a methodology to address disincentives and barriers to utility-provided energy efficiency and proposed to recover the costs of energy efficiency programs through a cost recovery factor. The hearing is scheduled to begin March 19, 2008. The final order is expected in June 2008.

New Mexico Energy Efficiency Legislation. On February 12, 2008, the New Mexico legislature passed House Bill 305, the Utility Customer Load Management bill. This bill modifies the 2005 Efficient Use of Energy Act and requires that electric utilities provide cost-effective energy efficiency programs that will produce savings of 5% of 2005 total retail kWh sales to New Mexico customers in calendar year 2014 and 10% of 2005 retail kWh sales to New Mexico customers in 2020. This legislation is expected to be signed by the governor.

2007 Long-Term Incentive Plan. On May 18, 2007, the Company filed for NMPRC approval for issuance of common stock for purposes of incentives and compensation. After the filing of supplemental testimony, the Hearing Examiner issued a Recommended Decision in July 2007 recommending that the securities transactions related to issuance of new stock be approved. The NMPRC requested additional supplemental testimony on the reasonableness of executive compensation and the effect on capital structure and rates to be set in the next general rate case. The Company filed supplemental testimony addressing these issues on October 31, 2007. Hearings on this matter were held on November 9, 2007. The Company is awaiting a final decision by the NMPRC.

New Mexico Investigation into Executive Compensation. In December 2007, the NMPRC initiated an investigation into executive compensation of investor-owned gas and electric public utilities. In its order initiating the investigation, the NMPRC required each utility to provide information on compensation of executive officers and directors for the period 1977-2006. The Company has provided the requested information. No further action has been taken by the NMPRC.

Generation CCN Filing. On July 18, 2007, the Company filed its application for issuance of a CCN to construct and operate Newman Unit 5. This case has been designated as NMPRC Case No. 07-00301-UT. The hearing was held on January 24, 2008. The Hearing Examiner issued a Recommended Decision on January 29, 2008 recommending Commission approval of the CCN. Pursuant to a request by the NMPRC, the Commission Staff and the Company provided additional information on February 26, 2008. A final order is expected in April 2008.

Federal Regulatory Matters

Transmission Dispute with Tucson Electric Power Company ("TEP"). In January 2006, the Company filed a complaint with the FERC to interpret the terms of a Power Exchange and Transmission Agreement (the "Transmission Agreement") entered into with TEP in 1982. TEP filed a complaint with the FERC one day later raising virtually identical issues. TEP claimed that, under the Transmission Agreement, it was entitled to up to 400 MW of firm transmission rights on the Company's transmission system that would enable it to transmit power from a new generating station (the Luna Energy Facility ("LEF") located near Deming, New Mexico) to Springerville or Greenlee in Arizona. The Company asserted that TEP's rights under the Transmission Agreement do not include transmission rights necessary to transmit such power as contemplated by TEP and that TEP must acquire any such rights in the open market from the Company at applicable tariff rates or from other transmission providers. On April 24, 2006, the FERC ruled in the Company's favor, finding that TEP does not have the transmission rights under the Transmission Agreement to transmit power from the LEF to Arizona. The ruling was based on written evidence presented and without an evidentiary hearing. TEP's request for a rehearing of the FERC's decision was granted in part and denied in part in an order issued October 4, 2006. The

October 4 order granted a hearing to examine the disputed evidence, and a hearing before an administrative law judge on the dispute was held on May 22 through May 24, 2007 and June 20, 2007.

The initial decision of the administrative law judge was issued September 6, 2007. The Presiding Judge generally found that the Transmission Agreement allows TEP to transmit power from the Deming Plant to Arizona but limits that transmission to 200 MW on any segment of the circuit and to non-firm service on the segment from Luna to Greenlee. The Company and TEP filed briefs on exceptions and replies to briefs on exceptions to the Initial Decision. In its brief on exceptions, TEP argued that it is entitled to a refund of the revenues the Company has received from TEP for transmission service to the Deming Plant during the pendency of these proceedings. In its response, the Company vigorously contested TEP's request for refunds. The Commission will issue a decision on the merits after review of the Initial Decision and the briefs on exceptions and replies to exceptions. While the Company believes that it will prevail on all points, the Company cannot predict the outcome of this case. During 2006 and 2007, TEP paid the Company $6.6 million for transmission service relating to the LEF. The Company has established a reserve for rate refund for $3.5 million related to this issue. If the FERC were to rule in TEP's favor, the Company may be required to refund all of the $6.6 million it has received from TEP for transmission service relating to the LEF and may lose the opportunity to receive compensation from TEP for such transmission service in the future. An adverse ruling by the FERC could have a negative effect on the Company's results of operations.

RTOs. FERC's rule on RTOs ("Order 2000") strongly encourages, but does not require, public utilities to form and join RTOs. The Company is an active participant in the development of WestConnect. The Company has entered into a Memorandum of Understanding ("MOU") with ten other transmission owners that obligates the parties to participate in and commit resources to ongoing joint efforts, including involvement with stakeholders, customers, local, state and federal regulatory personnel, and other Western Grid transmission providers to identify, develop and implement cost-effective wholesale market enhancements on a voluntary, phased-in basis to add value in transmission accessibility, wholesale market efficiency and reliability for wholesale users of the Western Grid. These enhancements may ultimately include formation of an RTO. WestConnect will continue to work with the FERC and two other proposed RTOs in the west to achieve a seamless market structure. The Company comprises approximately 7% of WestConnect and cannot control the terms or timing of its development. WestConnect as an RTO will not be operational for several years.

Department of Energy. The DOE regulates the Company's exports of power to the CFE in Mexico pursuant to a license granted by the DOE and a presidential permit. The DOE has determined that all such exports over international transmission lines shall be made in accordance with Order No. 888, which established the FERC rules for open access.

The DOE is authorized to assess operators of nuclear generating facilities a share of the costs of decommissioning the DOE's uranium enrichment facilities and for the ultimate costs of disposal of spent nuclear fuel. See "Facilities – Palo Verde Station – Spent Fuel Storage" for discussion of spent fuel storage and disposal costs.

Nuclear Regulatory Commission. The NRC has jurisdiction over the Company's licenses for Palo Verde and regulates the operation of nuclear generating stations to protect the health and safety of

the public from radiation hazards. The NRC also has the authority to grant license extensions pursuant to the Atomic Energy Act of 1954, as amended.

Sales for Resale

The Company entered into a contract to sell up to 100 MW firm energy and 50 MW of contingent energy to Imperial Irrigation District ("IID") which began May 1, 2007 and continues through April 30, 2009. The contract also provides for the Company to sell up to 100 MW firm energy and 40 MW of contingent energy beginning May 1, 2009 through April 30, 2010. To ensure that power is available to meet the IID contract demand, the Company entered into a contract effective May 1, 2007 to purchase up to 100 MW of firm energy from CreditSuisse Energy, LLC. This contract provides for firm energy to be delivered at Palo Verde through April 30, 2010 and/or 50 MW of energy delivered at Four Corners in the months of July through September 2007 and May through September for the years 2008 through 2010.

The Company provides up to 10 MW of firm capacity, associated energy, and transmission service to the Rio Grande Electric Cooperative pursuant to an ongoing contract which requires a two-year notice to terminate. In 2006 the Company provided RGEC with a notice of termination. Such termination will be effective as of March 31, 2008. The Company is discussing the provision of future electric service with RGEC.

Power Sales Contracts

The Company has entered into several short-term (three months or less) off-system sales contracts for the first quarter of 2008. The Company has also entered into other longer-term sales for which the supply is fully hedged.

Franchises and Significant Customers

El Paso Franchise

The Company has a franchise agreement with El Paso, the largest city it serves, through July 31, 2030. The franchise agreement includes a franchise fee of 3.25% of revenues and allows the Company to utilize public rights-of-way necessary to serve its retail customers within El Paso.

Las Cruces Franchise

In February 2000, the Company and Las Cruces entered into a seven-year franchise agreement with a franchise fee of 2% of revenues (approximately $1.5 million per year) for the provision of electric distribution service. Las Cruces exercised its right to extend the franchise for an additional two-year term ending April 30, 2009 and waived its option to purchase the Company's distribution system pursuant to the terms of the February 2000 settlement agreement.

Military Installations

The Company currently serves Holloman Air Force Base ("Holloman"), White Sands Missile Range ("White Sands") and the United States Army Air Defense Center at Fort Bliss ("Ft. Bliss"). The Company's sales to the military bases represent approximately 2% of annual operating revenues. The Company signed a contract with Ft. Bliss in December 1998 under which Ft. Bliss will take retail electric service from the Company through December 2008. In May 1999, the Army and the Company entered into a ten-year contract to provide retail electric service to White Sands. In March 2006, the Company signed a contract with Holloman that provides for the Company to provide retail electric service and limited wheeling services to Holloman for a ten-year term which expires in January 2016.

Item 1A. Risk Factors

Like other companies in our industry, our consolidated financial results will be impacted by weather, the economy of our service territory, market prices for power, fuel prices, and the decisions of regulatory agencies. Our common stock price and creditworthiness will be affected by local, regional and national macroeconomic trends, general market conditions and the expectations of the investment community, all of which are largely beyond our control. In addition, the following statements highlight risk factors that may affect our consolidated financial condition and results of operations. These are not intended to be an exhaustive discussion of all such risks, and the statements below must be read together with factors discussed elsewhere in this document and in our other filings with the SEC.

Our Costs Could Increase or We Could Experience Reduced Revenues if There are Problems at the Palo Verde Nuclear Generating Station

A significant percentage of our generating capacity, off-system sales margins, assets and operating expenses is attributable to Palo Verde. Our 15.8% interest in each of the three Palo Verde units totals approximately 633 MW of generating capacity. Palo Verde represents approximately 42% of our available net generating capacity and represented approximately 43% of our available energy for the twelve months ended December 31, 2007. Palo Verde comprises 41% of our total net plant-in-service and Palo Verde expenses comprise a significant portion of operation and maintenance expenses. APS is the operating agent for Palo Verde, and we have limited ability under the ANPP Participation Agreement to influence operations and costs at Palo Verde. Palo Verde operated at a capacity factor of 78.5% and 70.4% in the twelve months ended December 31, 2007 and 2006, respectively.

The NRC has placed Palo Verde Unit 3 in the "multiple repetitive degraded cornerstone" column of its action matrix which results in an enhanced NRC inspection regimen. We face the risk of additional or unanticipated costs at Palo Verde resulting from (i) increases in operation and maintenance expenses, including additional costs relating to the enhanced NRC oversight; (ii) increases in the cost of uranium; (iii) the replacement of reactor vessel heads at the Palo Verde units; (iv) an extended outage of any of the Palo Verde units; (v) increases in estimates of decommissioning costs; (vi) the storage of radioactive waste, including spent nuclear fuel; (vii) prolonged reductions in generating output; (viii) insolvency of other Palo Verde Participants; and (ix) compliance with the various requirements and regulations governing commercial nuclear generating stations.

Our ability to increase retail base rates in Texas is limited through June 2010. We cannot seek approval to increase our base rates in Texas in the event of increases in non-fuel costs or loss of revenue unless our return on equity falls below the bottom of a defined range which currently is approximately 8.3%. Our rates in New Mexico will be fixed until after the conclusion of the May 2009 rate filing. We cannot assure that revenues will be sufficient to recover any increased costs, including any increased costs in connection with Palo Verde or other operations, whether as a result of inflation, changes in tax laws or regulatory requirements, or other causes.

We May Not Be Able to Recover All of Our Fuel Expenses from Customers

In general, by law, we are entitled to recover our prudently incurred fuel and purchased power expenses from our customers in Texas and New Mexico. The 2007 New Mexico Stipulation provides for energy from the deregulated Palo Verde Unit 3 to be recovered through fuel and purchased power costs based upon the contract cost of capacity and fuel for power purchased under the existing SPS purchased power contract. The 2007 New Mexico Stipulation requires the Company to file its FPPCAC according to NMPRC rules, at which time any party may propose to change the price of capacity and related energy from Palo Verde Unit 3 after the SPS purchased power contract is terminated September 30, 2009. The fuel expense in New Mexico and Texas is subject to reconciliation by the Texas Commission and the NMPRC. Prior to the completion of a reconciliation, we record fuel and purchased power costs transactions such that fuel revenues equal fuel and purchased power expense including the repriced energy costs for Palo Verde Unit 3 in New Mexico. In the event that a disallowance occurs during a reconciliation proceeding, the amounts recorded for fuel and purchased power expenses could differ from the amounts we are allowed to collect from our customers and we would incur a loss to the extent of the disallowance.

In New Mexico, the FPPCAC allows us to reflect current fuel and purchased power expenses in the FPPCAC and to adjust for under-recoveries and over-recoveries with a two-month lag. In Texas, fuel costs are recovered through a fixed fuel factor that may be adjusted two times per year. If we materially under-recover fuel costs, we may seek a surcharge to recover those costs at the time of the next fuel factor filing. During periods of significant increases in natural gas prices such as occurred in 2005, the Company realizes a lag in the ability to reflect increases in fuel costs in its fuel recovery mechanisms. As a result, cash flow is impacted due to the lag in payment of fuel costs and collection of fuel costs from customers. At December 31, 2007 and December 31, 2006, the Company had deferred fuel balances of $27.7 million and $32.6 million, respectively. To the extent the fuel and purchased power recovery processes in Texas and New Mexico do not provide for the timely recovery of such costs, we could experience a material negative impact on our cash flow.

Equipment Failures and Other External Factors Can Adversely Affect Our Results

The generation and transmission of electricity require the use of expensive and complex equipment. While we have a maintenance program in place, generating plants are subject to unplanned outages because of equipment failure. We are particularly vulnerable to this due to the advanced age of several of our gas-fired generating units in or near El Paso. In addition, we are seeking to extend the lives of these plants. In the event of unplanned outages, we must acquire power from others at unpredictable costs in order to supply our customers and comply with our contractual agreements. This can materially increase our costs and prevent us from selling excess power at wholesale, thus reducing our profits. In addition, actions of other utilities may adversely affect our ability to use transmission lines to deliver or import power, thus subjecting us to unexpected expenses or to the cost and uncertainty of public policy initiatives. We are particularly vulnerable to this because a significant portion of our available energy (at Palo Verde and Four Corners) is located hundreds of miles from El Paso and Las Cruces and must be delivered to our customers over long distance transmission lines. In addition, Palo Verde's availability is an important factor in realizing off-system sales margins. These factors, as well as weather, interest rates, economic conditions, fuel prices and price volatility, are largely beyond our control, but may have a material adverse effect on our consolidated earnings, cash flows and financial position.

We May Not Be Able To Recover All Costs of New Generation

We have obtained from the Texas Commission, and have pending with the NMPRC, CCNs to construct a new generating unit (Newman Unit 5) in El Paso to meet our expected customers' demand for electricity. We have provided the estimated cost of constructing Newman Unit 5 to the Texas Commission and NMPRC. We have risks associated with completing the construction of Newman Unit 5 on time and within projected costs. In addition, we have risks associated with obtaining financing for Newman Unit 5 at reasonable rates as we expect to issue debt to finance a portion of the plant.

The cost of financing and constructing Newman Unit 5 will be reviewed in future rate cases in both Texas and New Mexico. To the extent that the Texas Commission or NMPRC determines that the costs of construction are not reasonable because of cost overruns, delays or other reasons, we may not be allowed to recover these costs from customers in base rates.

In addition, if the unit is not completed on time, we may be required to purchase power or operate less efficient generating units to meet customer requirements. Any replacement purchased power or fuel costs will be subject to regulatory review by the Texas Commission and NMPRC. We face financial risks to the extent that recovery is not allowed for any replacement fuel costs resulting from delays in the completion of Newman Unit 5.

Competition and Deregulation Could Result in a Loss of Customers and Increased Costs

As a result of changes in federal law, our wholesale and large retail customers already have, in varying degrees, alternate sources of power, including co-generation of electric power. Deregulation legislation is in effect in Texas requiring us to separate our transmission and distribution functions, which would remain regulated, from our power generation and energy services businesses, which would operate in a competitive market, in the future. In 2004, the Texas Commission approved a rule delaying retail competition in our Texas service territory. This rule identified various milestones that we must reach before retail competition can begin. The first milestone calls for the development, approval by the FERC, and commencement of independent operation of an RTO in the area that includes our service territory. This and other milestones are not likely to be achieved for a number of years. There is substantial uncertainty about both the regulatory framework and market conditions that would exist if and when retail competition is implemented in our Texas service territory, and we may incur substantial preparatory, restructuring and other costs that may not ultimately be recoverable. There can be no assurance that deregulation would not adversely affect our future operations, cash flows and financial condition.

Item 1B. Unresolved Staff Comments

None.

Executive Officers of the Registrant

The executive officers of the Company as of February 15, 2008, were as follows:

Name	Age	Current Position and Business Experience
J. Frank Bates	57	Interim President and Chief Executive Officer since February 2008; Executive Vice President and Chief Operating Officer from May 2005 to February 2008; Executive Vice President and Chief Operations Officer from November 2001 to May 2005.
Scott D. Wilson	54	Executive Vice President, Chief Financial and Administrative Officer since February 2006; Senior Vice President, Chief Financial Officer from May 2005 to February 2006; Vice President – Corporate Planning and Controller from February 2005 to May 2005; Controller from September 2003 to February 2005; Owner of Wilson Consulting Group from June 1992 to September 2003.
Steven P. Busser	39	Vice President – Treasurer and Chief Risk Officer since May 2006; Vice President – Regulatory Affairs and Treasurer from February 2005 to April 2006; Treasurer from February 2003 to February 2005; Assistant Chief Financial Officer from June 2002 to February 2003.
David G. Carpenter	52	Vice President – Corporate Planning and Controller since August 2005; Director – Texas Regulatory Services for American Electric Power Services Corporation from June 2000 to August 2005.
Robert C. Doyle	48	Vice President – New Mexico Affairs since February 2007; Director – New Mexico Affairs from January 2007 to February 2007; Manager – Corporate Projects Office from August 2004 to January 2007; Project Manager – Corporate Transition to Competition from January 2004 to August 2004; Supervisor – Distribution Dispatch December 2003; Project Manager – Transition November 2003; Supervisor – Distribution Dispatch from August 1999 to October 2003.
Fernando J. Gireud	50	Vice President – Safety, Environmental, Power Marketing and International Affairs since February 2006; Vice President – Power Marketing and International Business from February 2003 to February 2006; Vice President – International Business from July 2002 to February 2003.
Richard G. Gonzalez	51	Vice President – Human Resources since November 2007; Director of Human Resources for Petro Stopping Centers, L.P., from March 2004 to November 2007; Director of Human Resources for Electrolux from March 1996 to March 2004.
Hector Gutierrez, Jr.	60	Executive Vice President – External Affairs since June 2006; Managing Director – Governmental Operations, Hillco Partners from October 2002 to June 2006.
Helen Knopp	65	Vice President – Public Affairs since May 2006; Vice President – Customer and Public Affairs from April 1999 to April 2006.
Kerry B. Lore	48	Vice President – Administration since May 2003; Controller from October 2000 to May 2003.
Hector R. Puente	51	Vice President – Transmission and Distribution since May 2006; Vice President – Distribution from February 2006 to April 2006; Vice President – Power Generation from April 2001 to February 2006.
Andres Ramirez	47	Vice President – Power Generation since February 2006; Vice President – Safety, Environmental and Resource Planning from July 2005 to February 2006; Executive Director – Operations for Sempra Energy Texas Service from August 2004 to July 2005; Senior Vice President – Power Production for Austin Energy from 2001 to 2004.
Gary D. Sanders	49	General Counsel since February 2006; Assistant General Counsel and Assistant Secretary from July 2004 to February 2006; Assistant General Counsel from January 2003 to July 2004.
Guillermo Silva, Jr.	54	Corporate Secretary since February 2006; Vice President – Information Services from February 2003 to February 2006; Corporate Secretary from January 1994 to February 2003.
John A. Whitacre	58	Vice President – System Operations and Planning since May 2006; Vice President – Transmission from February 2006 to April 2006; Vice President – Transmission and Distribution from July 2002 to February 2006.

The executive officers of the Company are elected annually and serve at the discretion of the Board of Directors.

Item 2. Properties

The principal properties of the Company are described in Item 1, "Business," and such descriptions are incorporated herein by reference. Transmission lines are located either on private rights-of-way, easements, or on streets or highways by public consent.

In July 2007, the Company entered into an agreement to lease executive and administrative offices in El Paso, Texas under a lease which expires in May 2018 with three concurrent renewal options of five years each. On February 8, 2008, the Company exercised its right of first refusal in the lease agreement to purchase this office building. All obligations previously incurred relating to this lease were terminated.

In addition, the Company leases certain warehouse facilities in El Paso, Texas under a lease which expires in December 2009 with three concurrent renewal options of one year each. The Company also has several other leases for office and parking facilities which expire within the next six years.

Item 3. Legal Proceedings

The Company is a party to various legal actions. In many of these matters, the Company has excess casualty liability insurance that covers the various claims, actions and complaints. Based upon a review of these claims and applicable insurance coverage, to the extent that the Company has been able to reach a conclusion as to its ultimate liability, it believes that none of these claims will have a material adverse effect on the financial position, results of operations or cash flows of the Company.

On June 7, 2004, the City of Tacoma filed suit against the Company and other defendants in the United States District Court for the Western District of Washington *(City of Tacoma v. American Electric Power Service Corp., et al.,* C04-5325RBL). This complaint sought civil damages (including treble damages) from the Company and the other defendants for violations of certain antitrust provisions under the Sherman Act. This matter was filed in the United States District Court for the Western District of Washington and on February 11, 2005, the Court granted the Company's motion to dismiss the case. The City of Tacoma filed a notice of appeal with the U.S. Court of Appeals for the Ninth Circuit. On March 20, 2007, the Ninth Circuit entered an order dismissing the appeal pursuant to a stipulation of the parties. The dismissal is final and no further appeal may be filed.

On May 5, 2004, Wah Chang, a specialty metals manufacturer which operates a plant in Oregon, filed suit against the Company and other defendants in the United States District Court for the District of Oregon. *(Wah Chang v. Avista Corporation, et al.,* No. 04-619AS). The complaint also makes substantially the same allegations as were made in *City of Tacoma* and seeks the same types of damages. This matter was transferred to the same court that heard and dismissed the *City of Tacoma* lawsuit and on February 11, 2005, the Court granted the Company's motion to dismiss the case. Wah Chang filed notice of appeal with the U.S. Court of Appeals for the Ninth Circuit, and in November 2007, the Ninth Circuit upheld the dismissal of the suit. Wah Chang filed a motion for rehearing of the appeal, and on January 15, 2008, the Ninth Circuit denied Wah Chang's motion. While the Company believes that this matter is without merit and intends to defend itself vigorously in any further appeal by Wah Chang to the U.S. Supreme Court, the Company is unable to predict the outcome or range of possible loss.

See "Regulation" for discussion of the effects of government legislation and regulation on the Company.

Item 4. Submission of Matters to a Vote of Security Holders

No matter was submitted to vote of the Company's security holders through the solicitation of proxies or otherwise during the fourth quarter of 2007.

PART II

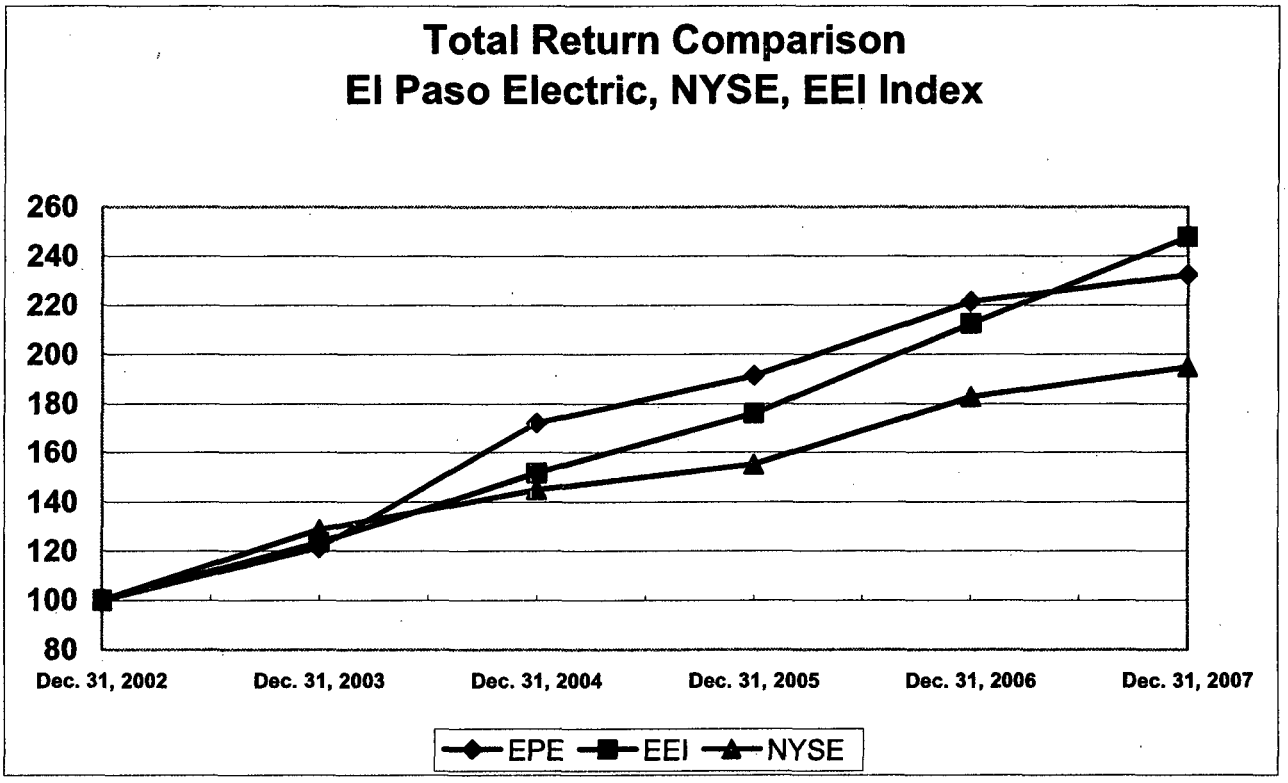
Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Repurchases of Equity Securities

The Company's common stock trades on the New York Stock Exchange under the symbol "EE." The high, low and close sales prices for the Company's common stock, as reported in the consolidated reporting system of the New York Stock Exchange for the periods indicated below were as follows:

	Sales Price		
	High	Low	Close (End of period)
2006			
First Quarter	$ 21.74	$ 18.80	$ 19.04
Second Quarter	20.37	18.15	20.16
Third Quarter	24.07	19.91	22.34
Fourth Quarter	25.05	22.16	24.37
2007			
First Quarter	$ 27.24	$ 22.95	$ 26.35
Second Quarter	28.19	24.08	24.56
Third Quarter	25.58	20.76	23.13
Fourth Quarter	26.81	22.27	25.57

Performance Graph

The following graph compares the performance of the Company's Common Stock to the performance of the NYSE Composite, and the Edison Electric Institute's Index of investor-owned electric utilities setting the value of each at December 31, 2002 to a base of 100. The table sets forth the relative yearly percentage change in the Company's cumulative total shareholder return as compared to the NYSE, and the EEI, as reflected in the graph.



	12/31/02	12/31/03	12/31/04	12/31/05	12/31/06	12/31/07
EPE	100	121	172	191	222	232
EEI	100	123	152	176	213	248
NYSE US	100	129	145	155	183	195

As of January 31, 2008, there were 3,856 holders of record of the Company's common stock. The Company does not anticipate paying dividends on its common stock in the near-term. The Company intends to continue its stock repurchase programs with the goal of managing its capital structure and enhancing shareholder value.

Since the inception of the stock repurchase programs in 1999, the Company has repurchased a total of approximately 19.3 million shares of its common stock at an aggregate cost of $269.4 million, including commissions. In September 2006, the Board of Directors (the "Board") authorized the repurchase of up to 2.3 million shares of the Company's outstanding common stock (the "2006 Plan"). During 2006 and 2007, the Company repurchased 4,005,158 shares of common stock under the 2006

Plan and under a previous plan approved by the Board in 2004 (the "2004 Plan") at an aggregate cost of $93.8 million. As of December 31, 2007, no shares remain available under the 2006 Plan or the 2004 Plan. In November 2007, the Board authorized the repurchase of up to an additional 2 million shares of the Company's outstanding common stock (the "2007 Plan"). No shares have been repurchased under the 2007 Plan. The Company may in the future make purchases of its common stock pursuant to the 2007 Plan in open market transactions at prevailing prices and may engage in private transactions where appropriate. The repurchased shares will be available for issuance under employee benefit and stock incentive plans, or may be retired.

For Equity Compensation Plan Information see Part III, Item 12 – Security Ownership of Certain Beneficial Owners and Management.

Item 6. Selected Financial Data

As of and for the following periods (in thousands except for share data):

	Years Ended December 31,				
	2007	2006	2005	2004	2003
Operating revenues	$ 877,427	$ 816,455	$ 803,913	$ 708,628	$ 664,362
Operating income	$ 128,321	$ 115,562	$ 107,883	$ 93,071	$ 79,370
Income before extraordinary item and cumulative effect of accounting change	$ 74,753	$ 61,387	$ 36,615	$ 33,369	$ 20,322
Extraordinary gain on re-application of SFAS No. 71, net of tax	$ –	$ 6,063	$ –	$ 1,802	$ –
Cumulative effect of accounting change, net of tax	$ –	$ –	$ (1,093)	$ –	$ 39,635
Net income	$ 74,753	$ 67,450	$ 35,522	$ 35,171	$ 59,957
Basic earnings per share:					
Income before extraordinary item and cumulative effect of accounting change	$ 1.64	$ 1.29	$ 0.77	$ 0.70	$ 0.42
Extraordinary gain on re-application of SFAS No. 71, net of tax	$ –	$ 0.13	$ –	$ 0.04	$ –
Cumulative effect of accounting change, net of tax	$ –	$ –	$ (0.02)	$ –	$ 0.82
Net income	$ 1.64	$ 1.42	$ 0.75	$ 0.74	$ 1.24
Weighted average number of shares outstanding	45,563,858	47,663,890	47,711,894	47,426,813	48,424,212
Diluted earnings per share:					
Income before extraordinary item and cumulative effect of accounting change	$ 1.63	$ 1.27	$ 0.76	$ 0.69	$ 0.42
Extraordinary gain on re-application of SFAS No. 71, net of tax	$ –	$ 0.13	$ –	$ 0.04	$ –
Cumulative effect of accounting change, net of tax	$ –	$ –	$ (0.02)	$ –	$ 0.81
Net income	$ 1.63	$ 1.40	$ 0.74	$ 0.73	$ 1.23
Weighted average number of shares and dilutive potential shares outstanding	45,928,478	48,164,067	48,307,910	48,019,721	48,814,761
Cash additions to utility property, plant and equipment	$ 144,588	$ 103,182	$ 88,263	$ 72,092	$ 77,679
Total assets	$ 1,853,888	$ 1,714,654	$ 1,665,449	$ 1,580,835	$ 1,596,614
Long-term debt and financing and capital lease obligations, net of current portion	$ 655,111	$ 616,130	$ 611,018	$ 379,636	$ 608,722
Common stock equity	$ 666,459	$ 579,675	$ 556,439	$ 532,147	$ 495,768

Certain amounts presented for prior years have been reclassified to conform to the 2007 presentation.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

As you read this Management's Discussion and Analysis, please refer to our Consolidated Financial Statements and the accompanying notes, which contain our operating results.

Summary of Critical Accounting Policies and Estimates

Note A to the Consolidated Financial Statements contains a summary of significant accounting policies. The preparation of our financial statements requires management to make estimates and assumptions that affect the amounts reported in the consolidated financial statements and related notes for the periods presented and actual results could differ in future periods from those estimates. Critical accounting policies and estimates are both important to the portrayal of our financial condition and results of operations and require complex, subjective judgments and include the following:

- Application of SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation"
- Collection of fuel expense
- Decommissioning costs and estimated asset retirement obligations
- Future pension and other postretirement benefit obligations
- Tax accruals

Application of SFAS No. 71

The Company applies the provisions of Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Certain Types of Regulation," ("SFAS No. 71") to its regulated operations in Texas and New Mexico. SFAS No. 71 requires a rate regulated enterprise to reflect the economic impact of regulatory decisions in its financial statements. As a result, we record certain costs or obligations as either assets or liabilities on our balance sheet and amortize them in subsequent periods. The deferral of costs as regulatory assets is appropriate only when the future recovery of such costs is probable. The application of SFAS No. 71 requires our management to make assumptions and estimates as to the amount of costs that regulatory authorities will ultimately permit us to recover. In the event we determine that we can no longer apply SFAS No. 71 to all or a portion of our operations, either as (i) a result of the establishment of retail competition in our service territory; (ii) a change in the regulatory approach for setting rates from cost-based ratemaking to another form of ratemaking; or (iii) other regulatory actions that restrict cost recovery to a level insufficient to recover costs, we could be required to record a charge against income in the amount of the remaining unamortized net regulatory assets. Such an action could materially reduce our shareholders' equity.

As of December 31, 2006, we determined that we met the criteria to re-apply SFAS No. 71 to our Texas jurisdiction, and we recorded regulatory assets of $9.6 million and associated accumulated deferred tax liabilities of $3.5 million, representing costs currently being recovered through the Texas fuel factor, which resulted in an extraordinary gain of $6.1 million, net of tax. We determined it was not appropriate at this time to recognize other potential regulatory assets and liabilities, such as the costs associated with refinancing our first mortgage bonds in 2005, because in our judgment they have not yet been included in our recoverable cost of service. We had previously made a determination to re-apply SFAS No. 71 to our New Mexico jurisdiction beginning July 1, 2004. At December 31, 2007, we had $27.8 million of regulatory assets, net of regulatory liabilities. We may record additional regulatory assets and regulatory liabilities in the future based on our judgment as to whether sufficient evidence exists that our regulators will include them in our rate base and or cost of service. Thus, the amount of our net regulatory assets could increase materially in the future. In addition, we include an allowance for equity and borrowed funds used during construction as a cost of construction of electric plant in service. The allowance for equity funds used during construction is recognized as other income and the allowance for borrowed

funds used during construction is shown as capitalized interest in our statement of operations. Under this treatment, we report higher other income and lower capitalized interest expense than we would have reported prior to the re-application of SFAS No. 71, and the difference may be material if our construction program continues at current levels or should increase relative to current levels. The factors that supported our decision are set forth in Note A to the consolidated financial statements.

Collection of Fuel Expense

In general, by law and regulation, our fuel and purchased power expenses are recovered from our customers. In times of rising fuel prices, we experience a lag in recovery of higher fuel costs. These costs are subject to reconciliation by the Texas Commission and the NMPRC. Prior to the completion of a reconciliation, we record fuel transactions such that fuel revenues equal fuel expense except for the fixed portion in New Mexico prior to July 2007. In the event that a disallowance occurs during a reconciliation proceeding, the amounts recorded for fuel and purchased power expenses could differ from the amounts we are allowed to collect from our customers, and we could incur a loss to the extent of the disallowance.

Decommissioning Costs and Estimated Asset Retirement Obligation

Pursuant to the ANPP Participation Agreement and federal law, we must fund our share of the estimated costs to decommission Palo Verde Units 1, 2 and 3 and associated common areas. We recorded a liability and a corresponding asset for the fair value of our decommissioning obligation upon implementation of SFAS No. 143, "Accounting for Asset Retirement Obligations." We will adjust the liability to its present value periodically over time, and the corresponding asset will be depreciated over its useful life. The determination of the estimated liability requires the use of various assumptions pertaining to decommissioning costs, escalation and discount rates.

We and other Palo Verde Participants rely upon decommissioning cost studies and make discount rate, rate of return and inflation projections to determine funding requirements and estimate liabilities related to decommissioning. Every third year outside engineers perform a study to estimate decommissioning costs associated with Palo Verde Units 1, 2 and 3 and associated common areas. We determine how we will fund our share of those estimated costs by making assumptions about future investment returns and future decommissioning cost escalations. The funds are invested in professionally managed investment trust accounts. We are required to establish a minimum accumulation and a minimum funding level in our decommissioning trust accounts at the end of each annual reporting period in accordance with the ANPP Participation Agreement. If actual decommissioning costs exceed our estimates, we would incur additional costs related to decommissioning. Further, if the rates of return earned by the trusts fail to meet expectations, we will be required to increase our funding to the decommissioning trust accounts. Although we cannot predict the results of future studies, we believe that the liability we have recorded for our decommissioning costs will be adequate to fund our share of the costs, assuming that Palo Verde Units 1, 2 and 3 operate over their remaining lives (which includes an assessment of the probability of a license extension) and that the DOE assumes responsibility for permanent disposal of spent fuel at plant shut down. We believe that our current annual funding levels of the decommissioning trust will adequately provide for the cash requirements associated with decommissioning. Historically, regulated utilities like us have been permitted to collect in rates in Texas and New Mexico the costs of nuclear decommissioning. Should we become subject to the Texas Restructuring Law, we will be able to collect from regulated transmission and distribution customers the costs of decommissioning. Reference is made to Note D, "Accounting for Asset Retirement Obligations" to the Notes to Consolidated Financial Statements.

Future Pension and Other Postretirement Obligations

Our obligations to retirees under various benefit plans are recorded as a liability on the consolidated balance sheets. Our liability is calculated on the basis of significant assumptions regarding discount rate, expected return on plan assets, rate of compensation increase and health care cost inflation. Our assumptions as well as a sensitivity analysis of the effect of hypothetical changes in certain assumptions are set forth in detail in Note K, "Employee Benefits", to the Notes to Consolidated Financial Statements. Changes in these assumptions could have a material impact on both net income and on the amount of liabilities reflected on the consolidated balance sheets.

In developing the assumptions, management makes judgments based on the advice of financial and actuarial advisors and our review of third-party and market-based data. These sources include life expectancy tables, surveys of compensation and health care cost trends, and historical and expected return data on various categories of plan assets. The assumed discount rate applied to future plan obligations is based at each measuring date on prevailing market interest rates inherent in high quality (AA and better) corporate bonds that would provide future cash flow needed to pay the benefits as they become due, as well as on publicly available bond issues. We regularly review our assumptions and conduct a reassessment at least once a year. We do not expect that any such change in assumptions will have a material effect on net income for 2008.

Tax Accruals

Our federal tax returns for the years 1999 through 2004 have been examined by the IRS. On June 12, 2007, we received from the IRS a notice of proposed deficiency for the tax years 1999 through 2004. A previous IRS notice of proposed deficiency had been received in 2005 for the years 1999 through 2002. The primary audit adjustments proposed by the IRS related to (i) whether we were entitled to currently deduct payments related to the repair of the Palo Verde Unit 2 steam generators or whether these payments should be capitalized and depreciated and (ii) whether we were entitled to currently deduct payments related to the dry cask storage facilities for spent nuclear fuel or whether these payments should be capitalized and depreciated. A tax deficiency was also received proposing to include in taxable income capital costs paid by third parties for construction of a switchyard. The third parties have indemnified the Company against any tax liability associated with the switchyard. The proposed IRS adjustments would affect the timing of these deductions, not their ultimate deductibility for federal tax purposes. We have protested the audit adjustments through administrative appeals. We believe that our treatment of the payments is supported by substantial legal authority. The IRS is currently performing an examination of the 2005 income tax return. We review our accruals for future liabilities under the provisions of the FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes," ("FIN 48"). FIN 48 provides a recognition threshold and measurement attribute for the financial statement measurement of tax positions. We have evaluated our tax positions under these provisions including the recognition of interest and penalties on tax benefits that have not been recognized. Although the ultimate outcome of the appeals and current examination cannot be predicted with certainty, we believe that, as of December 31, 2007, we have adequately recognized our expected tax liabilities.

Overview

The following is an overview of our results of operations for the years ended December 31, 2007, 2006 and 2005. Income for the years ended December 31, 2007, 2006 and 2005 is shown below:

	Years Ended December 31,		
	2007	2006	2005
Net income before extraordinary item and cumulative effect of accounting change (in thousands)	$ 74,753	$ 61,387	$ 36,615
Basic earnings per share before extraordinary item and cumulative effect of accounting change	1.64	1.29	0.77

The following table and accompanying explanations show the primary factors affecting the after-tax change in income before extraordinary items and cumulative effect of accounting change between the calendar years ended 2007 and 2006, 2006 and 2005, and 2005 and 2004 (in thousands):

	2007	2006	2005
Prior year December 31 income before extraordinary item and cumulative effect of accounting change	$ 61,387	$ 36,615	$ 33,369
Change in (net of tax):			
Increased retail base revenues	11,698 (a)	5,874 (a)	4,985 (a)
Increased (decreased) AFUDC and capitalized interest	6,189 (b)	(533)	1,681
Decreased (increased) administrative and general expense	3,471 (c)	(229)	715
Decreased (increased) maintenance at coal and gas-fired generating plants	3,516	(2,440)	147
Increased investment and interest income	1,983	516	1,377
Decreased (increased) taxes other than income taxes	846	(3,427) (d)	(1,514) (d)
Decreased (increased) transmission and distribution operations and maintenance expense	706	(4,230) (e)	(1,710)
Net fuel recoveries	173	3,635 (f)	(624)
Increased Palo Verde operations and maintenance expense	(7,114) (g)	(8,050) (h)	(2,189) (i)
Income tax adjustment	(6,174) (j)	6,174 (j)	–
Increased (decreased) off-system sales margins	(1,731)	2,797	456
Increased (decreased) wheeling revenues	(1,512)	3,665	1,485
Decreased (increased) interest charges on long-term debt	(751)	3,168 (k)	5,212 (k)
Decreased (increased) depreciation and amortization expense	(599)	8,694 (l)	6,760 (l)
Decreased (increased) loss on extinguishments of debt	–	12,128 (m)	(8,807) (m)
2004 IRS settlement	–	–	(6,200) (n)
Other	2,665	(2,970)	1,472
Current year December 31 net income before extraordinary item and cumulative effect of accounting change	$ 74,753	$ 61,387	$ 36,615

(a) Retail base revenues excludes fuel recovered through New Mexico base rates. Retail base revenues increased primarily due to increased kWh sales reflecting growth in the number of customers served in all periods presented above.
(b) Increased capitalized interest and AFUDC (allowance for funds used during construction) in 2007 are due to the reapplication of SFAS No. 71 to our Texas jurisdiction at December 31, 2006 and higher balances of construction work in progress and nuclear fuel subject to AFUDC and capitalized interest in 2007.
(c) Administrative and general expenses decreased due to an increase in capitalized employee salaries and benefits, decreased workers compensation insurance expense, and a sales tax refund in 2007.
(d) Taxes other than income taxes increased in 2006 compared to 2005 and 2005 compared to 2004 due to an increase in the El Paso city franchise fee rate which took effect in August 2005.
(e) Transmission and distribution operations and maintenance expense increased primarily due to increased wheeling expenses due to the expiration of an exchange contract and increased distribution expenses.
(f) Net fuel recoveries increased in 2006 compared to 2005 primarily due to the recovery of purchased power capacity payments in New Mexico in 2006 and increased recovery of transmission expenses in Texas.
(g) Palo Verde operations and maintenance expense increased in 2007 when compared to 2006 due to increased operations costs at all three units and increased maintenance costs at Unit 3 associated with the planned replacement of steam generators.
(h) Palo Verde operations and maintenance expense increased in 2006 when compared to 2005 due to the repairs and modification at Unit 1 and scheduled maintenance and refueling outages at Unit 2 and Unit 3 in 2006.
(i) Palo Verde operations and maintenance expense increased in 2005 when compared to 2004 due to increased operations and maintenance expense at Unit 1 during the planned replacement of steam generators and refueling outage in 2005, and increased administrative and general expenses.
(j) A reduction in income tax expense was recorded in 2006 to recognize the change in tax rates resulting from changes in the Texas franchise (income) tax law in May 2006 with no comparable activity in 2007 or 2005.
(k) Interest charges decreased in 2006 compared to 2005 and in 2005 compared to 2004 due to lower interest expense on long-term debt and financing obligations resulting from the refinancing of first mortgage bonds with long-term senior notes in May 2005 and the August 2005 reissuance and remarketing of pollution control bonds at lower interest rates.
(l) Depreciation and amortization decreased in 2006 compared to 2005 and 2005 compared to 2004 due to completing the recovery of certain fresh-start accounting related assets over the term of a rate stipulation in Texas Docket No. 12700 which ended in July 2005.
(m) Loss on extinguishments of debt in 2006 decreased compared to 2005 and increased in 2005 compared to 2004 reflecting the refinancing of all of our first mortgage bonds in May 2005.
(n) A benefit was recorded in the third quarter of 2004 from a settlement of an IRS audit of our 1996-1998 tax returns.

Historical Results of Operations

The following discussion includes detailed descriptions of factors affecting individual line items in the results of operations. The amounts presented below are presented on a pre-tax basis.

Operating revenues

We realize revenue from the sale of electricity to retail customers at regulated rates and the sale of energy in the wholesale power market generally at market based prices. Sales for resale (which are wholesale sales within our service territory) accounted for less than 1% of revenues. Off-system sales are wholesale sales into markets outside our service territory. Off-system sales are primarily made in off-peak periods when we have competitive generation capacity available after meeting our regulated service obligations. Under the terms of our rate agreements in Texas and New Mexico, we share 25% of our off-system sales margins with customers in Texas and New Mexico (effective July 1, 2005 and July 1, 2007, respectively). We also share 25% of transmission wheeling revenues in Texas. (See Note B of the Notes to Consolidated Financial Statements).

Revenues from the sale of electricity include the recovery of fuel costs, which are recovered from our customers through fuel adjustment mechanisms in Texas and New Mexico and a portion through base rates in New Mexico. We record deferred fuel revenues for the difference between fuel costs and fuel revenues until such amounts are collected from or refunded to customers. "Non-fuel base revenues" refers to our revenues from the sale of electricity excluding such fuel costs.

Retail non-fuel base revenue percentages by customer class are presented below:

	Twelve Months Ended December 31,		
	2007	2006	2005
Residential	40%	39%	40%
Commercial and industrial, small	36	36	36
Commercial and industrial, large	8	9	9
Sales to public authorities	16	16	15
Total retail non-fuel base revenues	100%	100%	100%

No retail customer accounted for more than 2% of our non-fuel base revenues during such periods. As shown in the table above, residential and small commercial customers comprise approximately 76% of our revenues. While this customer base is more stable, it is also more sensitive to changes in weather conditions. As a result, our business is seasonal, with higher kWh sales and revenues during the summer

cooling season. The following table sets forth the percentage of our revenues derived during each quarter for the periods presented:

	Years Ended December 31,		
	2007	2006	2005
January 1 to March 31	22%	22%	21%
April 1 to June 30	24	26	25
July 1 to September 30	30	29	30
October 1 to December 31	24	23	24
Total	100%	100%	100%

Heating and cooling degree days can be used to evaluate the effect of weather on energy use. For each degree the average outdoor temperature varies from a standard of 65 degrees Fahrenheit a degree day is recorded. The table below, shows heating and cooling degree days compared to a 10-year average for 2007, 2006 and 2005.

	2007	2006	2005	10-year Average
Heating degree days	2,286	2,020	2,176	2,329
Cooling degree days	2,512	2,457	2,549	2,525

Customer growth is a primary driver in our retail sales growth. The average number of retail customers grew 2.4% and 2.7% in 2007 and 2006, respectively. See the tables presented on pages 43 and 44 which provide detail on the average number of retail customers and the related revenues and kWh sales.

Retail non-fuel base revenues. Retail non-fuel base revenues increased by $18.6 million or 4.2% for the twelve months ended December 31, 2007 when compared to the same period in 2006 largely due to increased kWh sales associated with a 2.4% increase in the average number of retail customers served and colder winter weather in the first quarter of 2007 compared to the same period in 2006. Non-fuel base revenues to residential customers increased $8.9 million or 5.1% due to increased kWh sales. KWh sales to residential customers increased 5.6% in the twelve-month period compared to the same period last year largely as a result of a 2.1% increase in the average number of residential customers served and the colder winter weather in the first quarter of 2007. Heating degree days increased 13.2% while cooling degree days increased 2.2% for the twelve-month period in 2007 compared to the same period last year. Small commercial and industrial non-fuel base revenues increased $6.7 million or 4.2% in the twelve-month period ended December 31, 2007 reflecting an increase in kWh sales of 2.6% and a small increase in non-fuel base rates in New Mexico effective in July 2007. Other public authorities' non-fuel base revenues increased $4.3 million or 6.3% due to a 3.1% increase in kWh sales and a small increase in non-fuel base rates in New Mexico. Large commercial and industrial non-fuel base revenues decreased $1.4 million or 3.5% primarily due to customers migrating to the small commercial and industrial class.

Retail non-fuel base revenues increased by $9.5 million or 2.2% for the twelve months ended December 31, 2006 when compared to the same period in 2005. Retail kWh sales in the twelve month period ended December 31, 2006 were 2.5% higher than the twelve month period ended December 31, 2005. Growth of 2.7% in the average number of retail customers served in 2006 accounted for most of the increase in sales. The mild weather in the first quarter of 2006 was largely offset by warmer summer weather in the second quarter of 2006. Cooling and heating degree days for the twelve months ended

December 31, 2006 were approximately 3.6% and 7.2% below 2005, respectively. As a result, retail non-fuel base revenues for the residential, small commercial and industrial and other public authorities' customer classes increased primarily due to customer growth. Retail base revenues for large commercial and industrial increased primarily as a result of increased kWh sales to large industrial customers.

Fuel revenues. Fuel revenues consists of: (i) revenues collected from customers under fuel recovery mechanisms approved by the state commissions, (ii) deferred fuel revenues which are comprised of the difference between fuel costs and fuel revenues collected from customers and (iii) fuel costs recovered in base rates in New Mexico. In New Mexico, the fuel adjustment clause allows us to reflect current fuel costs above the amount recovered in base rates and to recover under-recoveries or refund over-recoveries with a two-month lag. Until terminated on July 1, 2007, a fixed amount of fuel costs was reflected in the fuel adjustment clause for 10% of kWh sales. In Texas, fuel costs are recovered through a fixed fuel factor that may be adjusted two times per year. In addition, if we materially over-recover fuel costs, we must seek to refund the over-recovery, and if we materially under-recover fuel costs, we may seek a surcharge to recover those costs.

In September 2007, we completed the recovery of $53.6 million of fuel under-recoveries through a fuel surcharge from our Texas customers which began in October 2005. We completed the recovery in January 2007 of $34 million of fuel under-recoveries, including interest through the surcharge period, through a fuel surcharge which began in February 2006. In 2007, 2006 and 2005, we collected $22.9 million, $56.9 million and $6.0 million of deferred fuel revenues in Texas through surcharges, respectively.

We under-collected current fuel costs and deferred for future recovery from our Texas and New Mexico customers by $17.8 million and $79.5 million in 2007 and 2005, respectively, compared to an over-collection of fuel costs of $3.7 million in 2006. At December 31, 2007, we had an under-recovered fuel balance of $29.2 million from our Texas customers and an over-recovery balance of $1.5 million from our New Mexico customers. At December 31, 2006, we had under-recovered fuel balances of $29.8 million from our Texas customers and $2.8 million from our New Mexico customers.

Off-system sales. Off-system sales are primarily made in off-peak periods when we have competitive generation capacity available after meeting our regulated service obligations. Typically, we realize between 40% and 50% of our off-system sales margins in the first quarter of each calendar year when our native load is lower than at other times of the year, allowing for the sale in the wholesale market of relatively larger amounts of off-system energy generated from lower cost generating resources. Palo Verde's availability is an important factor in realizing these off-system sales margins. The table below shows MWhs, sales revenue, fuel cost, total margins and retained margins made on off-system sales for the twelve months ended December 31, 2007, 2006 and 2005:

	Twelve Months Ended December 31,		
	2007	**2006**	**2005**
MWh sales	2,201,294	1,635,407	1,420,778
Sales revenues (in thousands)	$ 125,974	$ 95,932	$ 78,209
Fuel cost (in thousands)	$ 106,393	$ 73,332	$ 57,942
Total margins (in thousands)	$ 19,581	$ 22,600	$ 20,267
Retained margins (in thousands)	$ 15,514	$ 18,261	$ 13,750

Off-system sales increased $30.0 million or 31.3% for the twelve months ended December 31, 2007 when compared to 2006 primarily due to increased off-system kWh sales of 34.6%. We had increased energy available for sale in the twelve months of 2007 compared to the same period in 2006 primarily due to the increased energy generated at Palo Verde in the first six months of 2007 compared to the same period in 2006. This increase was partially offset by lower average market prices. Customers receive 25% of off-system sales margins in Texas and New Mexico pursuant to rate settlements. Prior to July 1, 2007, we retained 100% of off-system sales margins in New Mexico.

Off-system sales increased $17.7 million or 22.7% for the twelve months ended December 31, 2006 when compared to 2005 primarily due to increased off-system kWh sales of 15.1% and higher average market prices.

Comparisons of kWh sales and operating revenues are shown below (in thousands):

Years Ended December 31:	2007	2006	Increase (Decrease) Amount	Increase (Decrease) Percent
kWh sales:				
Retail:				
Residential	2,232,668	2,113,733	118,935	5.6%
Commercial and industrial, small	2,216,428	2,159,599	56,829	2.6
Commercial and industrial, large	1,195,038	1,204,707	(9,669)	(0.8)
Sales to public authorities	1,384,380	1,343,129	41,251	3.1
Total retail sales	7,028,514	6,821,168	207,346	3.0
Wholesale:				
Sales for resale	48,290	45,397	2,893	6.4
Off-system sales	2,201,294	1,635,407	565,887	34.6
Total wholesale sales	2,249,584	1,680,804	568,780	33.8
Total kWh sales	9,278,098	8,501,972	776,126	9.1
Operating revenues:				
Non-fuel base revenues:				
Retail:				
Residential	$ 184,562	$ 175,641	$ 8,921	5.1%
Commercial and industrial, small	168,091	161,359	6,732	4.2
Commercial and industrial, large	39,092	40,502	(1,410)	(3.5)
Sales to public authorities	72,763	68,438	4,325	6.3
Total retail non-fuel base revenues	464,508	445,940	18,568	4.2
Wholesale:				
Sales for resale	1,919	1,794	125	7.0
Total non-fuel base revenues	466,427	447,734	18,693	4.2
Fuel revenues:				
Recovered from customers during the period	197,383	225,441	(28,058)	(12.4) (1)
Under (over) collection of fuel	17,828	(3,655)	21,483	-
New Mexico fuel in base rates	51,487	30,033	21,454	71.4
Total fuel revenues	266,698	251,819	14,879	5.9
Off-system sales	125,974	95,932	30,042	31.3
Other	18,328	20,970	(2,642)	(12.6) (2)
Total operating revenues	$ 877,427	$ 816,455	$ 60,972	7.5
Average number of retail customers:				
Residential	315,114	308,483	6,631	2.1
Commercial and industrial, small	34,199	32,591	1,608	4.9
Commercial and industrial, large	56	58	(2)	(3.4)
Sales to public authorities	4,834	4,797	37	0.8
Total	354,203	345,929	8,274	2.4

(1) Excludes $22.9 million and $56.9 million of deferred fuel revenues recovered through Texas fuel surcharges in 2007 and 2006, respectively.

(2) Represents revenues with no related kWh sales.

Years Ended December 31:	2006	2005	Increase (Decrease) Amount	Increase (Decrease) Percent	
kWh sales:					
Retail:					
Residential	2,113,733	2,090,098	23,635	1.1%	
Commercial and industrial, small	2,159,599	2,126,918	32,681	1.5	
Commercial and industrial, large	1,204,707	1,165,506	39,201	3.4	
Sales to public authorities	1,343,129	1,270,116	73,013	5.7	
Total retail sales	6,821,168	6,652,638	168,530	2.5	
Wholesale:					
Sales for resale	45,397	41,883	3,514	8.4	
Off-system sales	1,635,407	1,420,778	214,629	15.1	
Total wholesale sales	1,680,804	1,462,661	218,143	14.9	
Total kWh sales	8,501,972	8,115,299	386,673	4.8	
Operating revenues:					
Non-fuel base revenues:					
Retail:					
Residential	$ 175,641	$ 173,007	$ 2,634	1.5%	
Commercial and industrial, small	161,359	158,406	2,953	1.9	
Commercial and industrial, large	40,502	39,192	1,310	3.3	
Sales to public authorities	68,438	65,861	2,577	3.9	
Total retail non-fuel base revenues	445,940	436,466	9,474	2.2	
Wholesale:					
Sales for resale	1,794	1,687	107	6.3	
Total non-fuel base revenues	447,734	438,153	9,581	2.2	
Fuel revenues:					
Recovered from customers during the period	225,441	164,500	60,941	37.0	(1)(2)
Under (over) collection of fuel	(3,655)	79,539	(83,194)	-	(2)
New Mexico fuel in base rates	30,033	29,440	593	2.0	
Total fuel revenues	251,819	273,479	(21,660)	(7.9)	
Off-system sales	95,932	78,209	17,723	22.7	
Other	20,970	14,072	6,898	49.0	(3)(4)
Total operating revenues	$ 816,455	$ 803,913	$ 12,542	1.6	
Average number of retail customers:					
Residential	308,483	300,581	7,902	2.6	
Commercial and industrial, small	32,591	31,573	1,018	3.2	
Commercial and industrial, large	58	59	(1)	(1.7)	
Sales to public authorities	4,797	4,658	139	3.0	
Total	345,929	336,871	9,058	2.7	

(1) Excludes $56.9 million and $6.0 million of deferred fuel revenues recovered through Texas fuel surcharges in 2006 and 2005, respectively.
(2) Reflects increases in Texas fixed fuel factors in October 2005 and February 2006.
(3) Primarily due to increased transmission revenue.
(4) Represents revenues with no related kWh sales.

Energy expenses

Our sources of energy include electricity generated from our nuclear, natural gas and coal generating plants and purchased power. Palo Verde represented approximately 42% of our available net generating capability and approximately 43% of our available energy for the twelve months ended December 31, 2007.

Our energy expenses increased $47.3 million for the twelve months ended December 31, 2007 when compared to 2006 primarily due to (i) increased natural gas costs of $37.7 million due to increased natural gas-fired generation, (ii) increased costs of purchased power of $9.8 million due to higher market prices for power, and (iii) increased nuclear fuel costs of $2.8 million due to increased generation. These increases were partially offset in 2007 by a $2.7 million refund related to a gas pipeline reservation fee and a $0.4 million decrease to our coal expense due to a decrease in the amount of coal burned.

Energy expenses decreased $12.6 million for the twelve months ended December 31, 2006 when compared to 2005 due to decreased natural gas generation and lower natural gas prices. During 2006, we were able to displace gas-fired generation with increased purchases of economy energy in the wholesale power market. The average cost of purchased power in 2006 was $52.97 per megawatt-hour compared to our cost of generating power at our gas-fired generating plants of $78.91 per megawatt-hour. In addition, the average cost of purchased power in 2006 was approximately 17% lower than in 2005. As a result, we purchased 76% more energy in 2006 compared to 2005 which resulted in increased costs of purchased power of $37.0 million.

	2007			2006		
Fuel Type	Cost (in thousands)	MWh	Cost per MWh	Cost (in thousands)	MWh	Cost per MWh
Natural Gas	$ 218,165 (a)	2,763,016	$ 78.96	$ 180,485	2,287,097	$ 78.91
Coal	11,343	714,164	15.88	11,698	827,181	14.14
Nuclear	23,993	4,229,915	5.67	21,173	3,793,728	5.58
Total	253,501	7,707,095	32.89	213,356	6,908,006	30.89
Purchased power	126,833	2,189,697	57.92	116,989	2,208,661	52.97
Total energy	$ 380,334	9,896,792	38.43	$ 330,345	9,116,667	36.24

	2005		
Fuel Type	Cost (in thousands)	MWh	Cost per MWh
Natural Gas	$ 230,900	2,643,584	$ 87.34
Coal	11,003 (b)	779,002	14.12
Nuclear	21,619	4,077,558	5.30
Total	263,522	7,500,144	35.14
Purchased power	80,040	1,255,626	63.75
Total energy	$ 343,562	8,755,770	39.24

(a) Excludes a reservation charge refund of $2.7 million recorded in 2007.
(b) Excludes a reduction of $0.7 million to our coal reclamation liability recorded in 2005.

Other operations expense

Other operations expense increased $4.4 million, or 2.3% in 2007 compared to 2006 primarily due to increased Palo Verde operations expense of $9.0 million. This increase was partially offset by decreased administrative and general expenses of $5.6 million related to a decrease in workers compensation insurance costs, an increase in capitalized employee salaries and benefits, and a decrease in legal expenses related to regulatory matters.

Other operations expense increased $13.2 million, or 7.4% in 2006 compared to 2005 primarily due to (i) increased Palo Verde operation expense of $5.1 million; (ii) increased transmission expense of $2.7 million primarily as the result of new wheeling contracts; (iii) increased customer accounts expense of $1.8 million due to increased bad debt expense; (iv) increased accruals for employee incentive payments of $2.9 million; and (v) increased consulting fees of $1.8 million.

Maintenance expense

Maintenance expense decreased $3.1 million, or 5.1% in 2007 compared to 2006 due to decreased maintenance expense at our gas-fired generating plants of $5.6 million as a result of the timing of planned maintenance, partially offset by increased maintenance expense at Palo Verde of $2.3 million.

Maintenance expense increased $12.7 million, or 26.8% in 2006 compared to 2005 primarily due to increased maintenance expense at Palo Verde of $7.9 million and our gas-fired generating plants of $3.9 million.

Depreciation and amortization expense

Depreciation and amortization expense increased $1.0 million in 2007 compared to 2006 primarily due to increased depreciable plant balances. Depreciation and amortization expense decreased $14.0 million in 2006 compared to 2005 primarily due to completing the recovery of certain fresh-start accounting related assets over the term of a rate stipulation in Texas Docket No. 12700 which ended in July 2005. The decrease was partially offset by increases in the depreciable plant balances, primarily related to the replacement of Palo Verde Unit 1 steam generators in December 2005.

Taxes other than income taxes

Taxes other than income taxes decreased $1.3 million in 2007 compared to 2006 primarily due to a decrease in property taxes and the change in the Texas franchise (income) tax law in 2006 which took effect in 2007. These decreases were partially offset by an increase in payroll taxes. Taxes other than income taxes increased $5.5 million in 2006 compared to 2005 primarily due to an increase in the El Paso city franchise fees which took effect in August 2005 and higher taxable revenues due to increased kWh sales and increases in fuel recoveries including fuel surcharges. We incur city franchise taxes as revenues are billed to customers.

Other income (deductions)

Other income (deductions) increased $7.7 million for the twelve months ended December 31, 2007 compared to the same period last year primarily due to (i) increased allowance for equity funds used during construction ("AEFUDC") due to the re-application of SFAS No. 71 to our Texas jurisdiction

beginning December 31, 2006 and increased construction work in progress subject to AEFUDC in 2007 and (ii) increased investment and interest income due to increased interest income on larger cash and decommissioning trust fund balances.

Other income (deductions) increased $20.8 million in 2006 compared to 2005 primarily due to a decrease in the loss on extinguishment of debt of $19.6 million, resulting from the retirement of our first mortgage bonds in the second quarter of 2005.

Interest charges (credits)

Interest charges (credits) decreased $1.3 million for the twelve months ended December 31, 2007 compared to the same period last year primarily due to an increase in allowance for borrowed funds used during construction as a result of the re-application of SFAS No. 71 to our Texas jurisdiction beginning December 31, 2006 and increased construction work in progress and nuclear fuel subject to AFUDC and capitalized interest. This decrease was partially offset by a $1.2 million increase in interest related to our nuclear fuel trust and our pollution control bonds.

Interest charges (credits) decreased $3.8 million in 2006 compared to 2005 due to a $5.1 million decrease in interest on long-term debt and financing obligations resulting from (i) the repurchase and retirement of our first mortgage bonds in May 2005; (ii) the May 2005 issuance of unsecured senior notes at a lower interest rate than the first mortgage bonds; and (iii) the reissuance and remarketing of our pollution control bonds in August 2005 with lower interest rates. This decrease was partially offset by a $0.2 million reduction in allowance for borrowed funds used during construction as a result of completing construction of new Palo Verde Unit 1 steam generators in December 2005.

Income tax expense

Income tax expense, before extraordinary item and the cumulative effect of an accounting change, increased $8.4 million and $7.5 million, respectively, for the twelve months ended December 31, 2007 compared to the same period in 2006 and the twelve months ended December 31, 2006 compared to the same period in 2005, due to increases in pretax income and certain permanent tax differences. The increase in 2007 compared to 2006 was partially offset by adjustments to income tax accruals related to prior years including an adjustment to deferred taxes associated with the accrual of other post-retirement benefits. The increase in income tax expense in 2006 compared to 2005 was partially offset by a reduction in state income taxes resulting from a change in the Texas franchise (income) tax law in 2006 as discussed below.

In May 2006, legislation was approved in Texas revamping the state franchise (income) tax. The tax legislation changes the franchise tax from a tax based upon either taxable capital or taxable income to a 1% tax on taxable margins. The revised franchise tax is effective for tax payments in 2008 based upon 2007 taxable margin. Our taxable margin is based upon revenues taxable for federal income tax purposes less cost of goods sold which includes all costs of producing electricity, but does not include post-production costs. Even with the lower tax rate, the expansion of the tax base resulted in higher franchise tax expense beginning in 2007.

For accounting purposes, the revised franchise tax is an income tax subject to the requirements of SFAS No. 109, "Accounting for Income Taxes". SFAS No. 109 requires that deferred tax assets and liabilities be adjusted for changes in tax law in the period of change. As a result, we recorded a $6.2 million

reduction in our net deferred tax liability in the second quarter of 2006 and a corresponding reduction in income tax expense. The adjustment to the net deferred income tax liability included: (i) a reduction of $2.7 million in net Texas deferred income tax liabilities associated with temporary differences that will not reverse in the future under the revised franchise tax calculation; (ii) a reduction of $6.8 million in net Texas deferred income tax liabilities for the change in tax rate from 4.5% to 1% effective in 2007; and (iii) an increase of $3.3 million in deferred federal income tax liabilities to reflect the change in deferred federal income taxes associated with deferred Texas franchise taxes.

Extraordinary gain

The extraordinary gain on re-application of SFAS No. 71 for 2006 relates to our determination that we met the criteria necessary to re-apply SFAS No. 71 to our Texas jurisdiction at December 31, 2006. The re-application of SFAS No. 71 to our Texas jurisdiction resulted in a $6.1 million extraordinary gain, net of tax, at December 31, 2006. For a full discussion on the re-application of SFAS No. 71 to our Texas jurisdiction, see Note A of Notes to Consolidated Financial Statements.

Cumulative effect of accounting change

The cumulative effect of accounting change for 2005 of a $1.1 million charge, net of tax, relates to the adoption of FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations," ("FIN 47") in December 2005. FIN 47 provides guidance on the recognition and measurement of liabilities associated with the retirement and disposal obligations of tangible long-lived assets not already accounted for under SFAS No. 143. FIN 47 affected the accounting for the disposal obligations of our fuel oil storage tanks, water wells, evaporative ponds and asbestos at our gas-fired generating stations.

Implementation of SFAS No. 71

Regulated electric utilities typically prepare their financial statements in accordance with SFAS No. 71. Under this accounting standard, certain recoverable costs are shown as either assets or liabilities on a utility's balance sheet if the regulator provides assurance that these costs will be charged to and collected from the utility's customers (or has already permitted such cost recovery). The resulting regulatory assets or liabilities are amortized in subsequent periods based upon their respective amortization periods in a utility's cost of service.

Prior to December 31, 2006 we did not prepare our financial statements in accordance with SFAS No. 71 for our Texas jurisdiction which had been operating under a rate freeze which expired on July 31, 2005. In July 2005, we entered into agreements ("Texas Rate Agreements") with El Paso, Texas Commission Staff and other parties in Texas that provide for most retail base rates to remain at their current level through June 30, 2010. During the rate freeze period, if our return on equity falls below the bottom of a defined range, we have the right to initiate a rate case and seek an adjustment to base rates. If our return on equity exceeds the top of the range, we will refund an amount equal to 50% of the pre-tax return in excess of the ceiling. The Texas Rate Agreements required the approval of the Texas Commission to implement the fuel related provisions of the agreements including the sharing of 25% of off-system sales margins with customers through our fixed fuel factor.

On December 8, 2006, the Texas Commission issued a final order approving the fuel related provisions of the Texas Rate Agreements and extending the rate freeze and earnings sharing provisions of the agreements to all customers in Texas based upon settlements with parties to the proceeding. Based

upon the Texas Rate Agreements and order of the Texas Commission extending the agreement to all customers in Texas, we determined that our Texas jurisdiction met the criteria for the re-application of SFAS No. 71 to our Texas jurisdiction as of December 31, 2006.

The re-application of SFAS No. 71 to our Texas jurisdiction recognizes that our rates are based upon our cost of providing service, and the earnings sharing provisions of the rate agreements provide for continued recovery of our costs of providing service during the rate freeze period. In addition, the adoption of a rule by the Texas Commission in October 2004 results in an indefinite delay in retail competition in our Texas service territory and the continued regulation of our retail rates by El Paso and the Texas Commission.

As a result of the re-application of SFAS No. 71 to our Texas jurisdiction at December 31, 2006, we recorded regulatory assets of $9.6 million and recognized an extraordinary gain of $6.1 million, net of tax. Regulatory assets recorded as of December 31, 2006 are currently being recovered through the Texas fixed fuel factor. Other regulatory assets and liabilities will be recorded when recognized in Texas rates. Effective with the re-application of SFAS No. 71 and in accordance with regulatory accounting requirements, we now recognize an allowance for equity and borrowed funds used during construction as a cost of construction of electric plant in service for Texas operations. The allowance for equity funds used during construction is recognized as income and the allowance for borrowed funds used during construction is shown as capitalized interest in our statement of operations. Prior to the re-application of SFAS No. 71, we capitalized interest costs in accordance with SFAS No. 34, "Capitalization of Interest Costs."

New accounting standards

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements." SFAS No. 157 defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures about fair value measurements. SFAS No. 157 modifies other accounting pronouncements that require or permit fair value measurements and does not require any new fair value measurements. This statement is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. SFAS No. 157 will not have a significant impact on our consolidated financial statements.

In February 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities – Including an Amendment of FASB Statement No. 115." SFAS No. 159 permits entities to choose to measure many financial instruments and certain other items at fair value at specified election dates without having to apply complex hedge accounting provisions. Unrealized gains and losses on items for which the fair value option has been elected should be reported in earnings at each subsequent reporting date. This statement is effective for financial statements issued for fiscal years beginning after November 15, 2007. We have determined that we will continue to recognize the fair value of our financial instruments under current elections and will not change the elections for the fair value measurement of any existing financial instruments under SFAS No. 159.

In December 2007, the FASB issued SFAS No. 141 (revised 2007), "Business Combinations" which replaces SFAS No. 141, "Business Combinations." SFAS No. 141 (revised 2007) applies the acquisition method of accounting to all transactions and other events in which one entity obtains control over one or more businesses and, therefore, improves the comparability of the information about business combinations provided in financial reports. This statement applies prospectively to business

combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008.

In December 2007, the FASB issued SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements – an amendment of ARB No. 51." SFAS No. 160 applies to all entities that prepare consolidated financial statements, except not-for-profit organizations, but will affect only those entities that have an outstanding noncontrolling interest in one or more subsidiaries or that deconsolidate a subsidiary. SFAS No. 160 amends Accounting Research Bulletin No. 51 ("ARB No. 51") to establish accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. This statement is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. We currently do not own a non-controlling interest in any subsidiaries the accounting for which would be impacted by SFAS No. 160.

For the last several years, inflation has been relatively low and, therefore, has had little impact on our results of operations and financial condition.

Liquidity and Capital Resources

Our principal liquidity requirements in the near-term are expected to consist of interest payments on our indebtedness, capital expenditures to expand and support electric service obligations, expenditures for nuclear fuel inventory and operating expenses including fuel costs and taxes. Cash flow from operations funded all of our capital requirements except nuclear fuel inventory for the year ended December 31, 2007 and we expect that cash flows from operations will continue to fund a significant portion of capital requirements. As of December 31, 2007, we had approximately $25.0 million in cash and short-term debt securities, a decrease of $15.1 million from the balance of $40.1 million on December 31, 2006.

Capital Requirements. Revenues from the sale of electricity include a recovery of fuel costs, which are essentially recovered from customers through fuel adjustment mechanisms in Texas and New Mexico and a portion through base rates in New Mexico. In Texas, fuel costs are recovered through a fixed fuel factor which may be adjusted twice a year. We record deferred fuel revenues for the under-recovery of fuel costs until they can be recovered from Texas customers. In September 2007, we completed the recovery in Texas of $53.6 million of fuel under-recoveries through a fuel surcharge which began in October 2005 and in January 2007 we completed the recovery in Texas of $34 million of fuel under-recoveries, including interest through the surcharge period, through a fuel surcharge which began in February 2006. The collection of $22.9 million of deferred fuel revenue through surcharges was largely offset by the under-collection of current fuel costs deferred for future recovery from our Texas customers of $22.4 million during 2007. As of December 31, 2007, we had a fuel under-recovery balance of $29.2 million from our Texas customers and an over-recovery balance of $1.5 million from our New Mexico customers. On January 8, 2008, we filed a petition ("PUC Docket No. 35204") with the Texas Commission to surcharge $30.1 million of under-recovered fuel costs and interest to our Texas customers. We anticipate beginning to collect this surcharge from our Texas customers in April 2008.

Our long-term liquidity requirements consist primarily of construction of electric utility plant and the payment of interest on debt. Capital requirements for new electric plant were $144.6 million for the year ended December 31, 2007 which were financed with cash flows from operations. Projected utility construction expenditures will consist primarily of expanding and updating the transmission and distribution systems, adding new generation, and making capital improvements and replacements at Palo Verde and other generating facilities. See Part I, Item 1, "Business – Construction Program." We expect that a significant portion of our construction expenditures will be financed with internal sources of funds through 2008 and the remainder financed with debt.

Our capital requirements for nuclear fuel increased substantially in 2007 as a result of increases in prices for uranium concentrates and increases in our inventory of nuclear fuel feedstock. We finance our nuclear fuel inventory through a trust that borrows under our $200 million credit facility to acquire and process the nuclear fuel. In 2007, borrowings under the credit facility for nuclear fuel increased $36.8 million to $83.0 million as of December 31, 2007 compared to an increase of $4.3 million in 2006 to $46.2 million as of December 31, 2006.

Our cash requirements for federal and state income taxes increased $20.6 million in 2007 as tax loss carryforwards were fully utilized in previous years. Future cash flow requirements for federal income taxes are expected to increase as the Texas fuel under-recovery balance is collected and becomes subject to income tax.

We continually evaluate our funding requirements related to our retirement plans, other postretirement benefit plans, and decommissioning trust funds. We contributed $13.6 million and $13.7 million to our retirement plans during the twelve months ended December 31, 2007 and 2006, respectively. We also contributed $3.4 million to our other postretirement benefit plan for both 2007 and 2006 and $7.0 million and $6.7 million to our decommissioning trust funds during the twelve months ended December 31, 2007 and 2006, respectively.

The Company does not pay dividends on common stock. Since 1999, we have repurchased approximately 19.3 million shares of common stock at an aggregate cost of $269.4 million, including commissions. During 2007, we repurchased 1,344,338 shares of common stock at an aggregate cost of $31.4 million. In November 2007, the Board authorized the repurchase of up to an additional 2 million shares of our outstanding common stock. No shares have been repurchased under the 2007 authorization. We financed capital requirements for common stock repurchases with cash flows from operations. We may make purchases of our stock in the future pursuant to our stock repurchase plan at open market prices and may engage in private transactions, where appropriate. The repurchased shares will be available for issuance under employee benefit and stock incentive plans, or may be retired. Common stock equity as a percentage of capitalization, including the current portion of long-term debt and financing obligations, was 49.7% as of December 31, 2007.

Capital Sources. We maintain the ability to issue long-term debt, if needed, to finance capital requirements and for other corporate purposes including the repurchase of common stock. Our Senior Notes are rated "Baa2" by Moody's and "BBB" by Standard & Poors. Construction expenditures are expected to increase as we plan to add new generation capacity in 2009 and subsequent years. Due to the increased volatility in the natural gas and nuclear fuel markets, we expanded our existing credit facility in July 2007 from $150 million to $200 million and increased the maximum authorized amount of the credit facility which is available for nuclear fuel borrowings from $70 million to $120 million. We expect to initially fund most of our construction expenditures with internally generated funds and, when

appropriate, borrow from our $200 million credit facility or issue long-term debt, consistent with maintaining a capital structure typical of an investment grade regulated electric utility.

Pollution Control Bonds Interest Rates. We currently have approximately $100.6 million of Pollution Control Bonds (the "PCBs") for which the interest rate is reset on a weekly "dutch auction" basis. The PCBs are insured by Financial Guaranty Insurance Company ("FGIC"). FGIC's bond ratings have recently been downgraded by all of the major rating agencies thereby calling into question FGIC's claims paying ability in the event of default by the Company. As a result, we have experienced increased yields and resulting interest expense for the PCBs. Although there has not yet been a failed auction of the PCBs, if one were to occur we would be required to pay a default interest rate of 15%. We are currently reviewing our alternatives as it relates to the PCBs and although a definitive decision has not yet been made, we may remarket or refinance the PCBs to fix the interest rates for these bonds for a yet undecided term.

Contractual Obligations. Our contractual obligations as of December 31, 2007 are as follows (in thousands):

	Payments due by period				
	Total	2008	2009 and 2010	2011 and 2012	2013 and Beyond
Long-Term Debt (including interest):					
Senior notes	$ 1,058,000	$ 24,000	$ 48,000	$ 48,000	$ 938,000
Pollution control bonds (1)	461,192	9,394	18,788	51,533	381,477
Financing Obligations (including interest):					
Nuclear fuel (2)	87,652	19,848	67,804	–	–
Purchase Obligations:					
Capacity contract with SPS (3)	241,993	11,688	23,918	24,700	181,687
Other power contracts	10,149	10,149	–	–	–
Fuel contracts:					
Coal (4)	80,360	9,440	18,881	18,881	33,158
Gas (4)	232,195	76,840	23,218	22,324	109,813
Nuclear fuel (5)	58,303	15,417	29,922	12,964	–
Retirement Plans and Other Postretirement benefits (6)	5,004	5,004	–	–	–
Decommissioning trust funds (7)	252,407	7,226	16,100	17,950	211,131
Operating leases (8)	2,025	1,069	791	136	29
Executive and administrative offices lease (9)	17,397	1,670	3,340	3,340	9,047
Total	$ 2,506,677	$ 191,745	$ 250,762	$ 199,828	$ 1,864,342

(1) Two series of pollution control bonds are remarketed and the interest rates are set weekly. The remaining two series of pollution control bonds are scheduled for remarketing and/or mandatory tender in 2012 and 2040.

(2) This reflects current obligations outstanding under the $200 million credit facility used to finance nuclear fuel including interest based on actual interest rates at the end of 2007.

(3) Amount includes $7.1 million contractual obligation for nine months in 2009. On January 29, 2008, we entered into an amendment to the original 20-year contract with SPS and agreed that the contract will terminate on September 30, 2009.

(4) Amount is based on the minimum volumes per the contract and market price at the end of 2007. Gas obligation includes a gas storage contract and a gas transportation contract.

(5) Some of the nuclear fuel contracts are based on a fixed price adjusted for an index. The index used is the current index at the end of 2007.
(6) These obligations include our minimum contractual funding requirements for the non-qualified retirement income plan and the other postretirement benefits for 2008. We have no minimum contractual funding requirement related to our retirement income plan for 2008. However, we may decide to fund at higher levels and expect to contribute $13.6 million and $3.4 million to our retirement plans and postretirement benefit plan in 2008, as disclosed in Part II, Item 8, Notes to Consolidated Financial Statements, Note K, Employee Benefits. Minimum contractual funding requirements for 2009 and beyond are not included due to the uncertainty of interest rates and the related return on assets.
(7) These obligations represent funding requirements under the ANPP Participation Agreement based on the current rate of return on investments.
(8) We lease certain warehouse facilities in El Paso, Texas under a lease which expires in December 2009 with three concurrent renewal options of one year each. We also have several other leases for office and parking facilities which expire within the next six years.
(9) In July 2007, we entered into an agreement to lease executive and administrative offices in El Paso, Texas under a lease which expires in May 2018 with three concurrent renewal options of five years each. On February 8, 2008, we exercised our right of first refusal in the lease agreement to purchase this office building. All obligations previously incurred relating to this lease were terminated.

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements that have or are reasonably likely to have a current or future effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

The following discussion regarding our market-risk sensitive instruments contains forward-looking information involving risks and uncertainties. The statements regarding potential gains and losses are only estimates of what could occur in the future. Actual future results may differ materially from those estimates presented due to the characteristics of the risks and uncertainties involved.

We are exposed to market risk due to changes in interest rates, equity prices and commodity prices. Substantially all financial instruments and positions we hold are for purposes other than trading and are described below.

Interest Rate Risk

Our long-term debt obligations are all fixed-rate obligations with varying maturities, except for two of our pollution control bond series which are repriced weekly and our revolving credit facility, which provides for nuclear fuel financing and working capital and which is based on floating rates.

We have issued two series of pollution control bonds in the amounts of $63.5 million and $37.1 million with a variable rate that is repriced weekly until they mature in 2040. These pollution control bonds are carried on the balance sheet at their face value. At December 31, 2007, the variable interest rates were 5.35% and 4.91% for the $63.5 million and the $37.1 million pollution control bond series, respectively. A hypothetical 10% increase in interest rates, annualized from the December 31, 2007 rate, would cause an approximate $0.5 million increase in interest expense. The weekly auction rate market is experiencing higher interest rates and higher rates of failure particularly in issuances such as ours which are backed by monoline insurance carriers. Although a failed auction has not yet been experienced, the default interest rates on the weekly auction rate securities we have outstanding is 15%. We are currently reviewing our alternatives as it relates to the PCBs and although a definitive decision has not yet been made, we may remarket or refinance the PCBs to fix the interest rates for these bonds for a yet undecided term.

To the extent the revolving credit facility is solely utilized for nuclear fuel purchases, interest rate risk, if any, related to the revolving credit facility is substantially mitigated through the operation of the Texas Commission and NMPRC rules which establish energy cost recovery clauses ("fuel clauses"). Under these rules and fuel clauses, energy costs, including interest expense on nuclear fuel financing, are recovered from our customers.

Our decommissioning trust funds consist of equity securities and fixed income instruments and are carried at market value. We face interest rate risk on the fixed income instruments, which consist primarily of municipal, federal and corporate bonds and which were valued at $54.1 million and $45.6 million as of December 31, 2007 and 2006, respectively. A hypothetical 10% increase in interest rates would reduce the fair values of these funds by $0.7 million and $0.7 million based on their fair values at December 31, 2007 and 2006, respectively.

Equity Price Risk

Our decommissioning trust funds include marketable equity securities of approximately $76.6 million and $69.1 million at December 31, 2007 and 2006, respectively. A hypothetical 20% decrease in equity prices would reduce the fair values of these funds by $15.3 million and $13.8 million based on their fair values at December 31, 2007 and 2006, respectively.

Commodity Price Risk

We utilize contracts of various durations for the purchase of natural gas, uranium concentrates and coal to effectively manage our available fuel portfolio. These agreements contain variable pricing provisions and are settled by physical delivery. The fuel contracts with variable pricing provisions, as well as substantially all of our purchased power requirements, are exposed to fluctuations in prices due to unpredictable factors, including weather and various other worldwide events, which impact supply and demand. However, our exposure to fuel and purchased power price risk is substantially mitigated through the operation of the Texas Commission and NMPRC rules and our fuel clauses, as discussed previously.

In the normal course of business, we enter into contracts of various durations for the forward sales and purchases of electricity to effectively manage our available generating capacity and supply needs. Such contracts include forward contracts for the sale of generating capacity and energy during periods when our available power resources are expected to exceed the requirements of our retail native load and sales for resale. They also include forward contracts for the purchase of wholesale capacity and energy during periods when the market price of electricity is below our expected incremental power production costs or to supplement our generating capacity when demand is anticipated to exceed such capacity. As of January 31, 2008, we had entered into forward sales and purchase contracts for energy as discussed in Part I, Item 1, "Business – Energy Sources – Purchased Power" and "Regulation – Power Sales Contracts." These agreements are generally fixed-priced contracts which qualify for the "normal purchases and normal sales" exception provided in SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," and SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities," including any effective implementation guidance discussed by the FASB Derivatives Implementation Group and are not recorded at their fair value in our financial statements. Because of the operation of the Texas Commission and NMPRC rules and our fuel clauses, these contracts do not expose us to significant commodity price risk.

Management Report on Internal Control Over Financial Reporting

The Company's management is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is defined in Rule 13a-15(f) or 15d-15(f) promulgated under the Securities Exchange Act of 1934 as a process designed by, or under the supervision of, the Company's principal executive and principal financial officers and affected by the Company's board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles and includes those policies and procedures that:

- Pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of the assets of the Company;

- Provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and the receipts and expenditures of the Company are being made only in accordance with authorizations of management and directors of the Company; and

- Provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

The Company's management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2007. In making this assessment, the Company's management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") in Internal Control-Integrated Framework.

Based on its assessment, management believes that, as of December 31, 2007, the Company's internal control over financial reporting is effective based on those criteria.

The Company's independent registered public accounting firm, KPMG LLP, has issued an audit report on the Company's internal control over financial reporting. This report appears on page 58 of this report.

Item 8. Financial Statements and Supplementary Data

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Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders
El Paso Electric Company:

We have audited the accompanying consolidated balance sheets of El Paso Electric Company and subsidiary as of December 31, 2007 and 2006, and the related consolidated statements of operations, comprehensive operations, changes in common stock equity, and cash flows for each of the years in the three-year period ended December 31, 2007. We also have audited El Paso Electric Company's internal control over financial reporting as of December 31, 2007, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). El Paso Electric Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on these consolidated financial statements and an opinion on the Company's internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the consolidated financial statements included 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. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

As discussed in Notes D, A, K, and H to the consolidated financial statements, the Company changed its accounting for conditional asset retirement obligations in 2005, share-based payments and defined benefit pension and other postretirement plans in 2006, and uncertainty in income taxes in 2007.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of El Paso Electric Company and subsidiary as of December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2007, in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, El Paso Electric Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

KPMG LLP

Houston, Texas
February 28, 2008

EL PASO ELECTRIC COMPANY AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS

ASSETS (In thousands)	December 31, 2007	December 31, 2006
Utility plant:		
Electric plant in service	$ 2,047,673	$ 1,958,787
Less accumulated depreciation and amortization	(858,426)	(799,579)
Net plant in service	1,189,247	1,159,208
Construction work in progress	185,122	134,470
Nuclear fuel; includes fuel in process of $47,256 and $8,632, respectively	113,330	66,261
Less accumulated amortization	(37,114)	(27,745)
Net nuclear fuel	76,216	38,516
Net utility plant	1,450,585	1,332,194
Current assets:		
Cash and cash equivalents	4,976	40,101
Investment in debt securities	20,000	–
Accounts receivable, principally trade, net of allowance for doubtful accounts of $2,873 and $2,999, respectively	84,578	86,730
Accumulated deferred income taxes	14,486	6,109
Inventories, at cost	34,234	31,390
Undercollection of fuel revenues	29,156	32,582
Prepayments and other	14,175	7,264
Total current assets	201,605	204,176
Deferred charges and other assets:		
Decommissioning trust funds	130,654	114,716
Regulatory assets	42,667	35,013
Other	28,377	28,555
Total deferred charges and other assets	201,698	178,284
Total assets	$ 1,853,888	$ 1,714,654

See accompanying notes to consolidated financial statements.

EL PASO ELECTRIC COMPANY AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS (Continued)

CAPITALIZATION AND LIABILITIES (In thousands)	December 31, 2007	2006
Capitalization:		
Common stock, stated value $1 per share, 100,000,000 shares authorized, 64,400,522 and 63,909,974 shares issued, and 119,403 and 110,854 restricted shares, respectively	$ 64,520	$ 64,021
Capital in excess of stated value	292,614	283,356
Retained earnings	565,701	489,082
Accumulated other comprehensive income (loss), net of tax	13,540	(18,316)
	936,375	818,143
Treasury stock, 19,370,266 and 18,025,928 shares, respectively, at cost	(269,916)	(238,468)
Common stock equity	666,459	579,675
Long-term debt, net of current portion	590,894	590,865
Financing obligations, net of current portion	64,217	25,265
Total capitalization	1,321,570	1,195,805
Current liabilities:		
Current portion of long-term debt and financing obligations	18,798	20,975
Accounts payable, principally trade	58,013	42,892
Taxes accrued	20,500	19,323
Interest accrued	4,347	4,390
Other	24,359	23,478
Total current liabilities	126,017	111,058
Deferred credits and other liabilities:		
Accumulated deferred income taxes	183,349	149,981
Accrued postretirement benefit liability	67,385	85,435
Asset retirement obligation	79,709	73,267
Accrued pension liability	30,088	56,260
Regulatory liabilities	14,876	15,079
Other	30,894	27,769
Total deferred credits and other liabilities	406,301	407,791
Commitments and contingencies		
Total capitalization and liabilities	$ 1,853,888	$ 1,714,654

See accompanying notes to consolidated financial statements.

EL PASO ELECTRIC COMPANY AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands except for share data)

	Years Ended December 31,		
	2007	2006	2005
Operating revenues	$ 877,427	$ 816,455	$ 803,913
Energy expenses:			
Fuel	250,789	213,356	262,870
Purchased and interchanged power	126,833	116,989	80,040
	377,622	330,345	342,910
Operating revenues net of energy expenses	499,805	486,110	461,003
Other operating expenses:			
Other operations	195,901	191,504	178,287
Maintenance	56,974	60,044	47,338
Depreciation and amortization	69,397	68,446	82,468
Taxes other than income taxes	49,212	50,554	45,027
	371,484	370,548	353,120
Operating income	128,321	115,562	107,883
Other income (deductions):			
Allowance for equity funds used during construction	5,708	882	856
Investment and interest income, net	9,605	6,456	5,625
Loss on extinguishments of debt	–	–	(19,561)
Miscellaneous non-operating income	1,431	861	1,121
Miscellaneous non-operating deductions	(4,386)	(3,589)	(4,186)
	12,358	4,610	(16,145)
Interest charges (credits):			
Interest on long-term debt and financing obligations	36,844	35,652	40,762
Other interest	804	1,092	699
Capitalized interest	(3,235)	(3,580)	(4,306)
Allowance for borrowed funds used during construction	(2,954)	(445)	(621)
	31,459	32,719	36,534
Income before income taxes, extraordinary item and cumulative effect of accounting change	109,220	87,453	55,204
Income tax expense	34,467	26,066	18,589
Income before extraordinary item and cumulative effect of accounting change	74,753	61,387	36,615
Extraordinary gain on re-application of SFAS No. 71, net of tax	–	6,063	–
Cumulative effect of accounting change, net of tax	–	–	(1,093)
Net income	$ 74,753	$ 67,450	$ 35,522
Basic earnings (losses) per share:			
Income before extraordinary item and cumulative effect of accounting change	$ 1.64	$ 1.29	$ 0.77
Extraordinary gain on re-application of SFAS No. 71, net of tax	–	0.13	–
Cumulative effect of accounting change, net of tax	–	–	(0.02)
Net income	$ 1.64	$ 1.42	$ 0.75
Diluted earnings (losses) per share:			
Income before extraordinary item and cumulative effect of accounting change	$ 1.63	$ 1.27	$ 0.76
Extraordinary gain on re-application of SFAS No. 71, net of tax	–	0.13	–
Cumulative effect of accounting change, net of tax	–	–	(0.02)
Net income	$ 1.63	$ 1.40	$ 0.74
Weighted average number of shares outstanding	45,563,858	47,663,890	47,711,894
Weighted average number of shares and dilutive potential shares outstanding	45,928,478	48,164,067	48,307,910

See accompanying notes to consolidated financial statements.

EL PASO ELECTRIC COMPANY AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF COMPREHENSIVE OPERATIONS
(In thousands)

	Years Ended December 31,		
	2007	2006	2005
Net income	$ 74,753	$ 67,450	$ 35,522
Other comprehensive income (loss):			
Unrecognized pension and postretirement benefit costs:			
Net gain arising during period	40,625	–	–
Reclassification adjustments included in net income for amortization of:			
Prior service cost	(2,754)	–	–
Net loss	3,385	–	–
Minimum pension liability adjustment	–	16,923	(6,128)
Net unrealized gains (losses) on marketable securities:			
Net holding gains (losses) arising during period	5,835	8,805	(1,693)
Reclassification adjustments for net (gains) losses included in net income	(1,683)	661	(666)
Net gains (losses) on cash flow hedges:			
Gains (losses) arising during period	–	–	(22,439)
Reclassification adjustment for interest expense included in net income	278	263	143
Total other comprehensive income (loss) before income taxes	45,686	26,652	(30,783)
Income tax benefit (expense) related to items of other comprehensive income (loss):			
Unrecognized pension and postretirement benefit costs	(18,037)	–	–
Minimum pension liability adjustment	–	(6,348)	2,299
Net unrealized gains (losses) on marketable securities	(830)	(1,893)	472
Gains (losses) on cash flow hedges	(104)	(99)	8,398
Total income tax benefit (expense)	(18,971)	(8,340)	11,169
Other comprehensive income (loss), net of tax	26,715	18,312	(19,614)
Comprehensive income	$ 101,468	$ 85,762	$ 15,908

See accompanying notes to consolidated financial statements.

EL PASO ELECTRIC COMPANY AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON STOCK EQUITY
(In thousands except for share data)

	Common Stock		Capital in Excess of Stated Value	Deferred and Unearned Compensation	Retained Earnings	Accumulated Other Comprehensive Income (Loss), Net of Tax	Treasury Stock		Total Common Stock Equity
	Shares	Amount					Shares	Amount	
Balances at December 31, 2004	62,768,180	$ 62,768	$ 268,771	$ 1,127	$ 386,110	$ (10,553)	15,365,108	$ (176,076)	$ 532,147
Grants of restricted common stock	104,907	105	1,870	(1,975)					–
Deferred compensation-restricted stock and performance shares				2,926					2,926
Stock awards withheld for taxes	(7,907)	(8)	(144)						(152)
Forfeitures of restricted common stock	(4,251)	(4)	(68)	72					–
Deferred taxes on stock incentive plan			170						170
Stock options exercised	646,500	646	4,794						5,440
Net income					35,522				35,522
Other comprehensive loss						(19,614)			(19,614)
Balances at December 31, 2005	63,507,429	63,507	275,393	2,150	421,632	(30,167)	15,365,108	(176,076)	556,439
Reclassification adjustment upon adoption of SFAS No. 123r			2,150	(2,150)					–
Restricted common stock grants and deferred compensation	77,054	77	1,317						1,394
Performance share awards	68,425	69	1,371						1,440
Stock awards withheld for taxes	(28,640)	(29)	(573)						(602)
Deferred taxes on stock incentive plan			955						955
Stock options exercised	396,560	397	2,743						3,140
Net income					67,450				67,450
Other comprehensive income						18,312			18,312
SFAS No. 158 adoption, net of tax of $3,879						(6,461)			(6,461)
Treasury stock acquired, at cost							2,660,820	(62,392)	(62,392)
Balances at December 31, 2006	64,020,828	64,021	283,356	–	489,082	(18,316)	18,025,928	(238,468)	579,675
Restricted common stock grants and deferred compensation	109,318	109	1,348						1,457
Performance share awards	58,650	59	660						719
Stock awards withheld for taxes	(28,492)	(28)	(669)						(697)
Forfeitures and lapsed restricted common stock	(24,379)	(25)	(4)						(29)
Deferred taxes on stock incentive plan			3,992						3,992
Stock options exercised	384,000	384	3,931						4,315
Net income					74,753				74,753
FIN 48 adoption					1,866				1,866
Other comprehensive income						26,715			26,715
Adjustment for tax effect of SFAS No. 158						5,141			5,141
Treasury stock acquired, at cost							1,344,338	(31,448)	(31,448)
Balances at December 31, 2007	64,519,925	$ 64,520	$ 292,614	$ –	$ 565,701	$ 13,540	19,370,266	$ (269,916)	$ 666,459

See accompanying notes to consolidated financial statements.

EL PASO ELECTRIC COMPANY AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	Years Ended December 31,		
	2007	2006	2005
Cash Flows From Operating Activities:			
Net income	$ 74,753	$ 67,450	$ 35,522
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization of electric plant in service	69,397	68,446	82,468
Amortization of nuclear fuel	18,166	15,387	15,575
Extraordinary gain on the re-application of SFAS No. 71, net of tax	–	(6,063)	–
Cumulative effect of accounting change, net of tax	–	–	1,093
Deferred income taxes, net	10,392	19,751	25,286
Allowance for equity funds used during construction	(5,708)	(882)	(856)
Loss on extinguishments of debt	–	–	19,561
Other amortization and accretion	12,173	12,945	11,961
Gain on sale of assets	(195)	(766)	(422)
Other operating activities	(561)	(941)	(110)
Change in:			
Accounts receivable	2,152	(10,724)	(5,296)
Inventories	(3,438)	(2,792)	(758)
Net recovery (deferral) of fuel revenues	4,886	59,749	(73,549)
Prepayments and other	(1,177)	(8,676)	(1,765)
Accounts payable	12,508	(3,858)	13,513
Taxes accrued	4,204	3,781	456
Interest accrued	(43)	(94)	(9,125)
Other current liabilities	(513)	720	(715)
Deferred charges and credits	(14,686)	4,565	(6,249)
Net cash provided by operating activities	182,310	217,998	106,590
Cash Flows From Investing Activities:			
Cash additions to utility property, plant and equipment	(144,588)	(103,182)	(88,263)
Cash additions to nuclear fuel	(52,400)	(17,602)	(15,888)
Proceeds from sale of assets	5,305	992	1,992
Capitalized interest and AFUDC:			
Utility property, plant and equipment	(8,662)	(4,238)	(5,330)
Nuclear fuel	(3,235)	(669)	(453)
Allowance for equity funds used during construction	5,708	882	856
Decommissioning trust funds:			
Purchases, including funding of $7.0 million, $6.7 million and $6.2 million, respectively	(116,165)	(106,403)	(42,381)
Sales and maturities	105,201	98,085	33,451
Purchases of debt securities	(20,000)	–	–
Other investing activities	192	867	(1,671)
Net cash used for investing activities	(228,644)	(131,268)	(117,687)
Cash Flows From Financing Activities:			
Proceeds from exercise of stock options	4,315	3,140	5,440
Acquisition of treasury stock	(31,448)	(62,392)	–
Settlement on derivative instruments classified as cash flow hedges	–	–	(22,439)
Proceeds from issuance of long-term notes payable	–	–	397,688
Repurchases of and payments on first mortgage bonds	–	–	(381,847)
Pollution control bonds:			
Proceeds	–	–	193,135
Payments	–	–	(193,135)
Financing obligations:			
Proceeds	56,083	20,373	18,138
Payments	(19,308)	(16,040)	(17,427)
Excess tax benefits from long-term incentive plans	2,395	1,417	–
Other financing activities	(828)	(1,083)	(9,901)
Net cash provided by (used for) financing activities	11,209	(54,585)	(10,348)
Net increase (decrease) in cash and temporary investments	(35,125)	32,145	(21,445)
Cash and temporary investments at beginning of period	40,101	7,956	29,401
Cash and temporary investments at end of period	$ 4,976	$ 40,101	$ 7,956

See accompanying notes to consolidated financial statements.

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EL PASO ELECTRIC COMPANY AND SUBSIDIARY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

A. Summary of Significant Accounting Policies

General. El Paso Electric Company is a public utility engaged in the generation, transmission and distribution of electricity in an area of approximately 10,000 square miles in west Texas and southern New Mexico. El Paso Electric Company also serves wholesale customers in Texas and periodically in the Republic of Mexico.

Principles of Consolidation. The consolidated financial statements include the accounts of El Paso Electric Company and its wholly-owned subsidiary, MiraSol Energy Services, Inc. ("MiraSol") (collectively, the "Company"). MiraSol, which began operations as a separate subsidiary in March 2001, provided energy efficiency products and services previously provided by the Company's Energy Services Business Group. On July 19, 2002, all sales activities of MiraSol ceased. MiraSol remains a going concern in order to satisfy current contracts and warranty and service obligations on previously installed projects. See Note I. All intercompany transactions and balances have been eliminated in consolidation.

Use of Estimates. The preparation of financial statements in conformity with 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.

Basis of Presentation. The Company maintains its accounts in accordance with the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission (the "FERC").

Application of SFAS No. 71. Regulated electric utilities typically prepare their financial statements in accordance with SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation." Under this accounting standard, certain recoverable costs are shown as either assets or liabilities on a utility's balance sheet if the regulator provides assurance that these costs will be charged to and collected from the utility's customers (or has already permitted such cost recovery). The resulting regulatory assets or liabilities are amortized in subsequent periods based upon their respective amortization periods in a utility's cost of service. Prior to December 31, 2006, the Company did not apply SFAS No. 71 to the Company's Texas jurisdictional operations. The Company's Texas jurisdiction had been operating under a rate freeze which expired on July 31, 2005. In July 2005, the Company entered into agreements ("Texas Rate Agreements") with El Paso, Texas Commission Staff and other parties in Texas that provide for most retail base rates to remain at their current level through June 30, 2010. During the rate freeze period if the Company's return on equity falls below the bottom of a defined range, the Company has the right to initiate a rate case and seek an adjustment to base rates. If the Company's return on equity exceeds the top of the range, the Company will refund an amount equal to 50% of the pre-tax return in excess of the ceiling. The Texas Rate Agreements required the approval of the Texas Commission to implement the fuel related provisions of the agreements including the

sharing of 25% of off-system sales margins with customers through the Company's fixed fuel factor. On December 8, 2006, the Texas Commission issued a final order approving the fuel related provisions of the Texas Rate Agreements and extending the rate freeze and earnings sharing provisions of the agreements to all customers in Texas based upon settlements with parties to the proceeding. Based upon the Texas Rate Agreements and order of the Texas Commission extending the agreements to all customers in Texas, the Company determined that the Company's Texas jurisdiction meets the criteria for the re-application of SFAS No. 71 to the Company's Texas jurisdiction as of December 31, 2006.

The re-application of SFAS No. 71 to the Company's Texas jurisdiction recognizes that the Company's rates are based upon the Company's cost of providing service, and the margin sharing provisions of the rate agreements provide for continued recovery of the Company's costs of providing service during the rate freeze period. In addition, the adoption of a rule by the Texas Commission in October 2004 results in an indefinite delay in retail competition in the Company's Texas service territory and the continued regulation of the Company's retail rates by El Paso and the Texas Commission.

As a result of the re-application of SFAS No. 71 to the Company's Texas jurisdiction at December 31, 2006, the Company recorded regulatory assets of $9.6 million, related accumulated deferred income tax liability of $3.5 million, and recognized an extraordinary gain of $6.1 million, net of tax. Regulatory assets recorded as of December 31, 2006 are currently being recovered through the Texas fixed fuel factor. Other regulatory assets and liabilities will be recorded when recognized in Texas rates. Effective with the re-application of SFAS No. 71 and in accordance with regulatory accounting requirements, the Company includes an allowance for equity and borrowed funds used during construction as a cost of construction of electric plant in service. The allowance for equity funds used during construction is recognized as income and the allowance for borrowed funds used during construction is shown as capitalized interest charges in the Company's statement of operations. Prior to the re-application of SFAS No. 71, the Company capitalized interest costs in accordance with SFAS No. 34, "Capitalization of Interest Costs."

Comprehensive Income. Certain gains and losses that are not recognized currently in the consolidated statements of operations are reported as other comprehensive income in accordance with SFAS No. 130, "Reporting Comprehensive Income."

Utility Plant. Depreciation is provided on a straight-line basis over the estimated remaining lives of the assets (ranging from 3 to 31 years), except for approximately $298 million of reorganization value allocated primarily to net transmission, distribution and general plant in service. This amount was depreciated on a straight-line basis over a ten-year period which ended in July 2005. For all other utility plant, Texas and New Mexico depreciation lives are the same.

The Company charges the cost of repairs and minor replacements to the appropriate operating expense accounts and capitalizes the cost of renewals and betterments. When property subject to

composite depreciation is retired or otherwise disposed of in the normal course of business, its original cost – together with the cost of removal, less salvage – is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation is removed from the balance sheet accounts and a gain or loss is recognized.

The cost of nuclear fuel is amortized to fuel expense on a units-of-production basis. A provision for spent fuel disposal costs is charged to expense based on the funding requirements of the Department of Energy (the "DOE") for disposal cost of approximately one-tenth of one cent on each kWh generated. The Company is also amortizing its share of costs associated with on-site spent fuel storage casks at Palo Verde over the burn period of the fuel that will necessitate the use of the storage casks. See Note C.

Impairment of Long-Lived Assets. In accordance with SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," long-lived assets, such as property, plant, and equipment and purchased intangibles subject to amortization, are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability of assets to be held and used is measured by a comparison of the carrying amount of an asset to estimated undiscounted future cash flows expected to be generated by the asset. If the carrying amount of an asset exceeds its estimated undiscounted future cash flows, an impairment charge is recognized for the amount by which the carrying amount of the asset exceeds the fair value of the asset.

AFUDC and Capitalized Interest. The Company capitalizes interest (ABFUDC) and common equity (AEFUDC) costs to construction work in progress and nuclear fuel in process in accordance with the FERC Uniform System of Accounts as provided for in SFAS No. 71. AFUDC is a non-cash component of income and is calculated monthly and charged to all new eligible construction and capital improvement projects. The AFUDC rate utilized in 2007 was 8.43%. Prior to December 31, 2006, the Company capitalized interest cost to construction work in progress and nuclear fuel in process in accordance with SFAS No. 34, "Capitalization of Interest Cost" for its Texas jurisdictional operations. The AFUDC rates applied for the New Mexico jurisdiction for 2006 and 2005 were 8.73% and 10.20%, respectively.

Asset Retirement Obligation. The Company complies with SFAS No. 143, "Accounting for Asset Retirement Obligations." SFAS No. 143 sets forth accounting requirements for the recognition and measurement of liabilities associated with the retirement of tangible long-lived assets. An asset retirement obligation ("ARO") associated with long-lived assets included within the scope of SFAS No. 143 is that for which a legal obligation exists under enacted laws, statutes, written or oral contracts, including obligations arising under the doctrine of promissory estoppel. Under the statement, these liabilities are recognized as incurred if a reasonable estimate of fair value can be established and are capitalized as part of the cost of the related tangible long-lived assets. The Company records the increase in the ARO due to the passage of time as an operating expense (accretion expense). Effective December 31, 2005, the Company adopted FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations," ("FIN 47"). FIN 47 clarifies that the term "conditional" as used in SFAS

No. 143, refers to a legal obligation to perform an asset retirement activity even if the timing and/or settlement are conditional on a future event that may or may not be within the control of an entity. See Note D.

Cash and Cash Equivalents. All temporary cash investments with an original maturity of three months or less are considered cash equivalents.

Investment in Debt Securities. The Company has invested excess cash for short periods of time in auction rate securities with contract maturity dates that extend beyond three months. These securities provide for interest rates to be reset on a short-term basis which typically provides a liquid market to sell the securities to meet cash requirements. The Company classifies the investments in auction rate securities in current assets as investment in debt securities in the consolidated balance sheets.

Investments. The Company's marketable securities, included in decommissioning trust funds in the balance sheets, are reported at fair market value and consist primarily of equity securities and municipal, federal and corporate bonds in trust funds established for decommissioning of its interest in Palo Verde. Such marketable securities are classified as "available-for-sale" securities and, as such, unrealized gains and losses are included in accumulated other comprehensive income as a separate component of common stock equity. However, if declines in fair value of marketable securities below original cost basis are determined to be other than temporary, then the declines are reported as losses in the consolidated statement of operations and a new cost basis is established for the affected securities at fair value. Gains and losses are determined using the cost of the security based on the specific identification basis. See Note M.

Derivative Accounting. The Company complies with SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities," including any effective implementation guidance discussed by the FASB Derivatives Implementation Group. This standard requires the recognition of derivatives as either assets or liabilities in the balance sheet with measurement of those instruments at fair value. Any changes in the fair value of these instruments are recorded in earnings or other comprehensive income. See Note M.

Inventories. Inventories, primarily parts, materials, supplies, fuel oil and natural gas are stated at average cost not to exceed recoverable cost.

Operating Revenues Net of Energy Expenses. The Company accrues revenues for services rendered, including unbilled electric service revenues. Energy expenses are stated at actual cost incurred. The Company's Texas retail customers are presently being billed under a fixed fuel factor approved by the Public Utility Commission of Texas ("Texas Commission"). The Company's New Mexico retail customers are being billed under base rates and a fuel adjustment clause which is adjusted monthly, as approved by the New Mexico Public Regulation Commission ("NMPRC"). The

Company's recovery of energy expenses in these jurisdictions is subject to periodic reconciliations of actual energy expenses incurred to actual fuel revenues collected. The difference between energy expenses incurred and fuel revenues charged to the Company's Texas and New Mexico customers, as determined under Texas Commission and NMPRC rules, is reflected as over/undercollection of fuel revenues in the consolidated balance sheets. See Note B.

Revenues. Accounts receivable include accrued unbilled revenues of $17.9 million and $18.0 million at December 31, 2007 and 2006, respectively. The Company presents sales net of sales taxes in its consolidated statements of operations.

Allowance for Doubtful Accounts. Additions, deductions and balances for allowance for doubtful accounts for 2007, 2006 and 2005 are as follows (in thousands):

	2007	2006	2005
Balance at beginning of year	$ 2,999	$ 2,474	$ 3,071
Additions:			
Charged to costs and expense	2,875	3,454	2,527
Recovery of previous write-offs	1,152	1,062	1,195
Uncollectible receivables written off	4,153	3,991	4,319
Balance at end of year	$ 2,873	$ 2,999	$ 2,474

Income Taxes. The Company accounts for federal and state income taxes under the asset and liability method of accounting for income taxes under the provisions of SFAS No. 109, Accounting for Income Taxes ("SFAS No. 109"). Under this method, deferred income taxes are recognized for the estimated future tax consequences of "temporary differences" by applying enacted statutory tax rates for each taxable jurisdiction applicable to future years to differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities. The effect on deferred tax assets and liabilities of a change in tax rate is recognized in income in the period that includes the enactment date. The Company recognizes tax assets and liabilities for uncertain tax positions in accordance with the recognition and measurement criteria of FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes ("FIN 48"). A tax liability has been established to recognize interest and penalties on tax benefits that have not been recognized. See Note H.

Earnings per Share. Basic earnings per share is computed by dividing net income by the weighted average number of shares outstanding. Diluted earnings per share is computed by dividing net income by the weighted average number of shares and the dilutive impact of the sum of unvested restricted stock, performance shares, and the stock options that were outstanding during the period with the amount of outstanding options calculated using the treasury stock method.

Stock-Based Compensation. The Company has a stock-based long-term incentive plan. Effective January 1, 2006, the Company adopted SFAS No. 123 (revised) "Accounting for Stock – Based

Compensation," which requires a public entity to measure the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award (with some limited exceptions). Such cost will be recognized over the period during which an employee is required to provide service in exchange for the award (the "requisite service period") which typically will be the vesting period. Compensation cost is not recognized for anticipated forfeitures prior to vesting of equity instruments. SFAS No. 123 (revised) applies to all awards granted after January 1, 2006 and to awards modified, repurchased or cancelled after that date. Additionally, compensation cost for outstanding awards for which the requisite service has not been rendered as of January 1, 2006 shall be expensed as the requisite service is rendered on or after such date. The compensation cost for that portion of awards shall be based on the grant-date fair value of those awards as calculated for pro forma disclosure under SFAS No. 123. SFAS No. 123 (revised) replaces SFAS No. 123, "Accounting for Stock – Based Compensation," and supersedes APB Opinion No. 25, "Accounting for Stock Issued to Employees," and related interpretations. See Note E.

If compensation expense for the incentive plans had been amortized on a straight-line basis over the vesting period, consistent with the provisions of SFAS No. 123 (revised), the Company's net earnings and earnings per share for 2005 would have been reduced to the proforma amounts presented below (in thousands, except for per share data):

	Years Ended December 31, 2005
Net income, as reported	$ 35,522
Deduct: Compensation expense, net of tax	806
Pro forma net income	$ 34,716
Basic earnings per share:	
As reported	$ 0.75
Pro forma	0.73
Diluted earnings per share:	
As reported	0.74
Pro forma	0.72

Prior to the adoption of SFAS No. 123 (revised), the Company presented all tax benefits for deductions resulting from the exercise of share-based compensation as operating cash flows in the Condensed Consolidated Statement of Cash Flows. SFAS No. 123 (revised) requires the benefits of tax deductions in excess of the taxes expensed on recognized compensation cost to be reported as financing cash flows.

Other New Accounting Standards. In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements." SFAS No. 157 defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures about fair value measurements. SFAS No. 157 modifies other accounting pronouncements that require or permit fair

value measurements and does not require any new fair value measurements. This statement is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. SFAS No. 157 will not have a significant impact on the Company's consolidated financial statements.

In February 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities – Including an Amendment of FASB Statement No. 115." SFAS No. 159 permits entities to choose to measure many financial instruments and certain other items at fair value at specified election dates without having to apply complex hedge accounting provisions. Unrealized gains and losses on items for which the fair value option has been elected should be reported in earnings at each subsequent reporting date. This statement is effective for financial statements issued for fiscal years beginning after November 15, 2007. The Company has determined that it will continue to recognize the fair value of its financial instruments under current elections and will not change the elections for the fair value measurement of any existing financial instruments under SFAS No. 159.

In December 2007, the FASB issued SFAS No. 141 (revised 2007), "Business Combinations" which replaces SFAS No. 141, "Business Combinations." SFAS No. 141 (revised 2007) applies the acquisition method of accounting to all transactions and other events in which one entity obtains control over one or more businesses and, therefore, improves the comparability of the information about business combinations provided in financial reports. This statement applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008.

In December 2007, the FASB issued SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements – an amendment of ARB No. 51." SFAS No. 160 applies to all entities that prepare consolidated financial statements, except not-for-profit organizations, but will affect only those entities that have an outstanding noncontrolling interest in one or more subsidiaries or that deconsolidate a subsidiary. SFAS No. 160 amends Accounting Research Bulletin No. 51 ("ARB No. 51") to establish accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. This statement is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. The Company currently does not own a non-controlling interest in any subsidiaries the accounting for which would be impacted by SFAS No. 160.

Pension and Postretirement Benefit Accounting. For a full discussion of the Company's accounting policies for its employee benefits. See Note K.

Reclassification. Certain amounts in the consolidated financial statements for 2006 and 2005 have been reclassified to conform with the 2007 presentation.

B. Regulation

General

The rates and services of the Company are regulated by incorporated municipalities in Texas, the Texas Commission, the NMPRC, and the FERC. The Texas Commission and the NMPRC have jurisdiction to review municipal orders, ordinances, and utility agreements regarding rates and services within their respective states and over certain other activities of the Company. The FERC has jurisdiction over the Company's wholesale transactions. The decisions of the Texas Commission, NMPRC and the FERC are subject to judicial review.

Texas Regulatory Matters

Texas Rate Agreements. The Company has entered into agreements ("Texas Rate Agreements") with El Paso, Commission Staff and other parties in Texas that provide for most retail base rates to remain at their current level through June 30, 2010. During the rate freeze period, if the Company's return on equity falls below the bottom of a defined range, the Company has the right to initiate a rate case and seek an adjustment to base rates. If the Company's return on equity exceeds the top of the range, the Company will refund an amount equal to 50% of the pretax return in excess of the ceiling. The range is based upon a risk premium above a twelve month average of comparable credit quality bond yields, and at a twelve month average of such bond yields the range would be approximately 8.3% to 12.3%. During 2007 the Company's return on equity fell within this range.

Pursuant to a rate agreement with El Paso in July 2005, the Company agreed to share with its Texas customers 25% of off-system sales margins and wheeling revenues among other provisions. Under the prior rate agreement, the Company shared 50% of off-system sales margins and wheeling revenues with Texas customers. A request for approval of the off-system sales and wheeling revenue sharing provision was filed with the Texas Commission in January 2006 ("PUC Docket No. 32289").

In PUC Docket No. 32289, the Company entered into settlement agreements with the Texas Commission Staff, a large industrial customer, El Paso, Texas Ratepayers Organization to Save Energy, and the Office of the Attorney General of the State of Texas (the "State") which (i) extended the rate freeze to all customers in Texas; (ii) extended the earnings sharing provisions to all customers in Texas; (iii) expanded the Company's support of low-income energy efficiency programs; and (iv) provided that after the expiration of the Texas Rate Agreements, the Company will treat wheeling revenues and expenses associated with non-native load in a manner consistent with then-existing Texas Commission rules and other substantive and procedural law. In addition, the agreement with the State provides for the Company to share 90% of off-system sales margins with customers after June 30, 2010 through June 30, 2015. This provision is not binding on the Texas Commission or other settling parties. In addition, the Company agreed that upon the expiration of the rate freeze, it would file a full base rate case with the Texas Commission and the applicable cities having original jurisdiction if requested to do so by the Texas Commission staff, El Paso, the State or the Texas Office of Public Utility Counsel. The

Company also retained the right to voluntarily file a full base rate case. On December 8, 2006, the Texas Commission approved the margin sharing provisions of the Texas Rate Agreements in PUC Docket No. 32289 pursuant to the settlement agreements.

Fuel and Purchased Power Costs. Although the Company's base rates are frozen under the Texas Rate Agreements, pursuant to Texas Commission rules and the Texas Rate Agreements, the Company's fuel costs including purchased power energy costs are recoverable from its customers. In January and July of each year, the Company can request adjustments to its fixed fuel factor to more accurately reflect projected energy costs associated with providing electricity, seek recovery of past undercollections of fuel revenues, and refund past overcollections of fuel revenues. All such fuel revenue and expense activities are subject to periodic final review by the Texas Commission in fuel reconciliation proceedings.

On August 31, 2007, the Company filed for authority to reconcile its eligible fuel expenses and revenues for the period of March 1, 2004 through February 28, 2007 ("Reconciliation Period"), which was assigned PUC Docket No. 34695. The Company is seeking to reconcile a total of $548.4 million in eligible fuel, fuel-related, and purchased power expenses to generate and purchase electric energy for its Texas retail customers. At the conclusion of the Reconciliation Period, the Company had a cumulative under-recovery of such expenses of $18.2 million of which $17.6 million was subject to an existing fuel surcharge. The Company is seeking to carry over the cumulative Reconciliation Period fuel under-recovery balance into the subsequent reconciliation period beginning March 2007. Hearings on the fuel reconciliation are scheduled in May 2008. A final order is not expected to be issued until the third quarter of 2008.

On January 8, 2008, the Company filed a request with the Texas Commission to surcharge approximately $30.1 million of under-recovered fuel and purchased power costs and interest over a twelve month period beginning in March 2008. The fuel under-recoveries were incurred during the period December 2005 through November 2007. A decision from the Texas Commission is expected in the first quarter of 2008.

On January 5, 2006, the Company filed a petition ("PUC Docket No. 32240") with the Texas Commission to increase its fixed fuel factors and to surcharge under-recovered fuel costs. The Company requested an increase in its Texas jurisdiction fixed fuel factors of $30.8 million or 16% annually to reflect an average cost of natural gas of $9.35 per MMBtu. The Company also requested a fuel surcharge to recover over a twelve-month period approximately $34 million of fuel undercollections, including interest, for under-recoveries for the period September 2005 through November 2005. The requested fuel factor and fuel surcharge were placed into effect on an interim basis subject to refund effective with February 2006 bills to customers. This proceeding was abated pending the Texas Commission's decision in the margin sharing proceeding, PUC Docket No. 32289, which was approved December 8, 2006. The Company filed a unanimous settlement with the Texas Commission to resolve all issues in this docket on January 24, 2007. The settlement provided for approval of the fuel surcharge and fuel factor for the period February 2006 through January 2007, the end of the surcharge period. In

addition, the Company agreed to reduce its fixed fuel factors by 10% effective February 1, 2007 reducing annual fuel recoveries by approximately $20.0 million per year. The revised fixed fuel factors reflect natural gas prices of approximately $7.80 per MMBtu. A final order approving the settlement in PUC Docket No. 32240 was issued by the Texas Commission on March 15, 2007.

Generation CCN Filing. On July 6, 2007, the Company filed a petition with the Texas Commission requesting a Certificate of Convenience and Necessity ("CCN") for two generating facilities in PUC Docket No. 34494. The first such facility is a natural-gas fueled power generating unit to be located at an existing plant site in El Paso. This facility is known as Newman Unit 5. The Newman Unit 5 project consists of 280 to 290 MW of natural gas-fired combined cycle generating capacity that the Company presently plans to construct in two phases. The first phase includes two 70 MW gas turbines to be installed by the peak of 2009. The second phase converts the unit into a combined cycle combustion turbine with a total capacity of 280 to 290 MW and is expected to be completed by late 2010 or early 2011.

The Newman Unit 5 will operate mostly in a baseload manner, but can also be used in a load following manner. It will be the most efficient gas-fired unit on the Company's system when operated in combined cycle.

The Company also requested a CCN for two renewable energy wind turbines currently operating at the Hueco Mountains Wind Ranch, the acquisition of which the Texas Commission had previously found to be consistent with the public interest.

On December 17, 2007, the parties to PUC Docket No. 34494 filed a Stipulation, signed by all parties, which recommended approval of the Company's requests. On January 31, 2008, the Texas Commission issued an order approving the requested CCNs. The costs of the project have not been approved.

Palo Verde Performance Standards. The Texas Commission established performance standards for the operation of Palo Verde pursuant to which each Palo Verde unit is evaluated annually to determine whether its three-year rolling average capacity factor entitles the Company to a reward or subjects it to a penalty. The capacity factor is calculated as the ratio of actual generation to maximum possible generation. If the capacity factor, as measured on a station-wide basis for any consecutive 36-month period, should fall below 52.5%, the parties to the Texas Rate Agreements can seek different rate treatment for Palo Verde. The removal of Palo Verde from rate base could have a significant negative impact on the Company's revenues and financial condition. The Company has calculated the performance rewards for the reporting periods ending in 2007 and 2006 to be approximately $0.6 million and $0.4 million, respectively. The 2006 reward was included along with energy costs incurred and fuel revenue billed as part of the Texas Commission's review during the 2007 fuel reconciliation proceeding as discussed above. Under the performance standards the Company did not earn a performance reward nor incur a penalty for the 2005 reporting period. Performance rewards are not recorded on the Company's books until the Texas Commission has ordered a final determination in a fuel proceeding or

comparable evidence of collectibility is obtained. Performance penalties would be recorded when assessed as probable by the Company.

In a prior fuel reconciliation proceeding ("PUC Docket No. 20450"), the Company agreed to contribute any Palo Verde rewards in its next fuel reconciliation to assist low-income customers in paying their utility bills. In compliance with the Texas Commission's order, the Company sought and received approval by the El Paso City Council in January 2006 to remit to El Paso approximately $5.8 million in Palo Verde performance reward funds to fund demand side management programs such as weatherization with a focus on programs to assist small business and commercial customers. As of December 31, 2007 $5.6 million, including accrued interest, remains to be paid under these agreements and is recorded as a liability on the Company's balance sheet.

Deregulation. The Texas Restructuring Law required certain investor-owned electric utilities to separate power generation activities and retail service activities from transmission and distribution activities by January 1, 2002, and on that date, retail competition for generation services was instituted in some parts of Texas. However, the Texas Commission has delayed retail competition in the Company's Texas service territory by approving a rule which identifies various milestones for the Company to reach before competition can begin. The first milestone calls for the development, approval by the FERC, and commencement of independent operation of a regional transmission organization (RTO) in the area that includes the Company's service territory, including the development of retail market protocols to facilitate retail competition (see "FERC Regulatory Matters – RTO" below). The complete transition to retail competition would occur upon the completion of the last milestone, which would be the Texas Commission's final evaluation of the market's readiness to offer fair competition and reliable service to all retail customers. The Company believes this rule delays retail competition in El Paso indefinitely. There is substantial uncertainty about both the regulatory framework and market conditions that will exist if and when retail competition is implemented in the Company's service territory, and the Company may incur substantial preparatory, restructuring and other costs that may not ultimately be recoverable. There can be no assurance that deregulation would not adversely affect the future operations, cash flows and financial condition of the Company.

Renewable Energy Requirements. Notwithstanding the Texas Commission's approval of a rule further delaying competition in the Company's Texas service territory, the Company became subject to the renewable energy and energy efficiency requirements of the Texas Restructuring Law on January 1, 2006. Under the renewable energy requirements, the Company is required to annually obtain its pro rata share of renewable energy credits as determined by the Program Administrator (the Electric Reliability Council of Texas). The Company's ultimate obligation to obtain renewable energy credits will not be known until January 31 of the year following the compliance year, and it will have until March 31 to obtain, if necessary, and submit to the Program Administrator, sufficient credits. The Company obtained the required renewable energy credits to meet its expected obligations through 2007.

2007 Energy Efficiency Legislation. New energy efficiency legislation was approved in Texas in June 2007. The new legislation establishes new and increased goals for additional cost-effective energy

efficiency for residential and commercial customers equivalent to at least (i) 10% of the annual growth in peak demand for residential and commercial customers by December 31, 2007; (ii) 15% of the annual growth in demand by December 31, 2008; and (iii) 20% of the annual growth in demand by December 31, 2009. Among other things, the new legislation requires the Texas Commission to establish an energy efficiency cost recovery factor for ensuring cost recovery for utility expenditures made to satisfy the energy efficiency goal. The legislation provides that utilities that are unable to establish an energy efficiency cost recovery factor in a timely manner due to a rate freeze will be allowed to defer the costs of complying with the energy efficiency goal and recover such deferred costs at the end of the rate freeze period.

New Mexico Regulatory Matters

2007 New Mexico Stipulation. On July 3, 2007, the NMPRC issued a final order approving a stipulation ("2007 New Mexico Stipulation") addressing all issues in the 2006 rate filing in Case No. 06-00258-UT. On July 26, 2007, the NMPRC modified its final order to clarify that its approval of the Stipulation did not preclude the NMPRC from examining the Company's rates upon its own motion at any time prior to the date stipulated for the Company's next rate filing. The 2007 New Mexico Stipulation provides for a $5.8 million non-fuel base rate increase and a $0.3 million fuel and purchased power decrease relative to test year rates. The 2007 New Mexico Stipulation reflects average natural gas costs of $7.20 per MMBtu for the June 2007 through May 2008 forecast period. Most of the Company's fuel and purchased power costs during the period of the 2007 New Mexico Stipulation are expected to be recovered through base rates. Any difference between actual fuel and purchased power costs and the amount included in base rates will be recovered or refunded through the Fuel and Purchased Power Cost Adjustment Clause ("FPPCAC"). Rates will continue in effect until changed by the NMPRC after the Company's next rate case. The 2007 New Mexico Stipulation requires the Company to file its next general rate case no later than May 30, 2009 using a base period of the twelve months ending December 31, 2008. Under NMPRC statutes, new rates would become effective no later than June 2010.

The 2007 New Mexico Stipulation provides for energy from the deregulated Palo Verde Unit 3 to be recovered through fuel and purchased power costs based upon the contract cost of capacity and fuel for power purchased under the existing SPS purchased power contract. The 2007 New Mexico Stipulation eliminates the fixed fuel and purchased power cost of $0.021 per kWh for 10% of New Mexico kWh sales and requires 25% of jurisdictional off-system sales margins to be credited to customers through the FPPCAC. Consistent with the Texas settlement in PUC Docket No. 32289, beginning in July 2010 through June 2015, the Company will credit 90% of the New Mexico jurisdictional portion of off-system sales margins to New Mexico customers through the FPPCAC. No later than two years after implementation, the 2007 New Mexico Stipulation requires the Company to file to continue its FPPCAC according to NMPRC rules, at which time any party may propose to change the price of capacity and related energy from Palo Verde Unit 3 since the SPS purchased power contract will terminate in September 2009. The 2007 New Mexico Stipulation results in final reconciliation of

fuel and purchased power costs for the period May 31, 2004 through December 31, 2005. The Company will continue to file annual reconciliation statements for fuel and purchased power costs in accordance with NMPRC rules. The Company filed a reconciliation statement for the period June 1, 2006 through May 31, 2007 on August 31, 2007.

Fuel and Purchased Power Costs. The Company currently recovers fuel and purchased power costs in base rates in an average amount of $0.04288 per kWh and recovers the remaining fuel and purchased power costs through its FPPCAC. See discussion of 2007 New Mexico Stipulation above.

Notice of Investigation of Rates. On August 3, 2007, the Company received by mail a "Notice of Investigation of Rates of El Paso Electric Company" from the NMPRC in Case No. 07-00317-UT (the "Notice"). On August 21, 2007, the NMPRC requested the Company to file a response to the issues, including the reasonableness of fuel and purchased power costs. On September 7, 2007, the Company filed its response and requested that the NMPRC suspend its investigation and close the docket. No further action has been taken by the Commission. The Company is unable at this time to predict any potential negative financial impact from this docket.

Renewables. The New Mexico Renewable Energy Act of 2004 as amended by the 2007 New Mexico legislature requires that, by January 1, 2006, renewable energy comprise no less than 5% of the Company's total retail sales to New Mexico customers. This requirement has been fixed at 6% until January 1, 2011, when the renewable portfolio standard increases to 10% of the Company's total retail sales to New Mexico customers. After 2011, the renewable portfolio standard, as a percentage of total retail sales to New Mexico customers, increases to 15% by 2015 and 20% by 2020. The Company has met all requirements to date.

The NMPRC approved the Company's 2006 annual procurement plan ("Procurement Plan") in December 2006, including the purchase of renewable energy certificates ("RECs") and the issuance of a diversity RFP for renewable resources to meet future requirements. In addition, the NMPRC authorized the Company to enter into two 20-year purchased power agreements to purchase energy from an 8 MW low-emissions biomass generating facility and from a 6 kW solar energy generating facility. Both generating facilities would have been located within the Company's New Mexico service area. The biomass renewable supplier defaulted on its contract obligations. In the Order approving the 2006 Plan, the NMPRC approved recovery of REC costs, without associated energy, through the FPPCAC. The NMPRC's decision to allow recovery of REC costs, without associated energy, through the FPPCAC was appealed to the New Mexico Supreme Court (the "Court") by the New Mexico Industrial Energy Consumers. The Court issued a decision on August 28, 2007, ordering that RECs without associated energy could not be recovered through the FPPCAC, but the costs would be recovered through the ratemaking process. The Company filed a request to create a deferral as provided under New Mexico law, with carrying costs, to recover these costs and refunded to customers the previously-collected REC costs recovered through the FPPCAC. NMPRC action to approve the deferral, with carrying costs, is pending.

The Company filed its 2007 annual Procurement Plan on August 31, 2007. The Company has proposed procurement of Texas RECs to complete its 2008 and 2009 renewable obligations. The Company also requested funding to conduct a proposal process in 2008 to attempt to procure diverse renewable energy resources to meet NMPRC requirements. The Company is seeking a deferral of the costs associated with renewable compliance, including carrying costs. Hearings were held on November 29, 2007. The Hearing Examiner issued the Recommended Decision on December 5, 2007 recommending that the Company's request to replace the biomass project with Texas RECs be rejected and that the Company include a plan to replace these RECs with New Mexico RECs in its next procurement plan filing. The Company filed exceptions to the Recommended Decision on December 14, 2007. A NMPRC order adopting the Recommended Decision was issued on February 27, 2008.

New Mexico Energy Efficiency Plan Filing. On November 5, 2007, the Company filed its Application for Approval of Energy Efficiency and Load Management Programs. This case has been designated as NMPRC Case No. 07-00411-UT. In this filing, the Company requests approval of a number of energy efficiency programs. The Company also proposed a methodology to address disincentives and barriers to utility-provided energy efficiency and proposed to recover the costs of energy efficiency programs through a cost recovery factor. The hearing is scheduled to begin March 19, 2008. The final order is expected in June 2008.

New Mexico Energy Efficiency Legislation. On February 12, 2008, the New Mexico legislature passed House Bill 305, the Utility Customer Load Management bill. This bill modifies the 2005 Efficient Use of Energy Act and requires that electric utilities provide cost-effective energy efficiency programs that will produce savings of 5% of 2005 total retail kWh sales to New Mexico customers in calendar year 2014 and 10% of 2005 retail kWh sales to New Mexico customers in 2020. This legislation is expected to be signed by the governor.

2007 Long-Term Incentive Plan. On May 18, 2007, the Company filed for NMPRC approval for issuance of common stock for purposes of incentives and compensation. After the filing of supplemental testimony, the Hearing Examiner issued a Recommended Decision in July 2007 recommending that the securities transactions related to issuance of new stock be approved. The NMPRC requested additional supplemental testimony on the reasonableness of executive compensation and the effect on capital structure and rates to be set in the next general rate case. The Company filed supplemental testimony addressing these issues on October 31, 2007. Hearings on this matter were held on November 9, 2007. The Company is awaiting a final decision by the NMPRC.

New Mexico Investigation into Executive Compensation. In December 2007, the NMPRC initiated an investigation into executive compensation of investor-owned gas and electric public utilities. In its order initiating the investigation, the NMPRC required each utility to provide information on compensation of executive officers and directors for the period 1977-2006. The Company has provided the requested information. No further action has been taken by the NMPRC.

Generation CCN Filing. On July 18, 2007, the Company filed its application for issuance of a CCN to construct and operate Newman Unit 5. This case has been designated as NMPRC Case No. 07-00301-UT. The hearing was held on January 24, 2008. The Hearing Examiner issued a Recommended Decision on January 29, 2008 recommending Commission approval of the CCN. Pursuant to a request by the NMPRC, the Commission Staff and the Company provided additional information on February 26, 2008. A final order is expected in April 2008.

Federal Regulatory Matters

Transmission Dispute with Tucson Electric Power Company ("TEP"). In January 2006, the Company filed a complaint with the FERC to interpret the terms of a Power Exchange and Transmission Agreement (the "Transmission Agreement") entered into with TEP in 1982. TEP filed a complaint with the FERC one day later raising virtually identical issues. TEP claimed that, under the Transmission Agreement, it was entitled to up to 400 MW of firm transmission rights on the Company's transmission system that would enable it to transmit power from a new generating station (the Luna Energy Facility ("LEF") located near Deming, New Mexico) to Springerville or Greenlee in Arizona. The Company asserted that TEP's rights under the Transmission Agreement do not include transmission rights necessary to transmit such power as contemplated by TEP and that TEP must acquire any such rights in the open market from the Company at applicable tariff rates or from other transmission providers. On April 24, 2006, the FERC ruled in the Company's favor, finding that TEP does not have the transmission rights under the Transmission Agreement to transmit power from the LEF to Arizona. The ruling was based on written evidence presented and without an evidentiary hearing. TEP's request for a rehearing of the FERC's decision was granted in part and denied in part in an order issued October 4, 2006. The October 4 order granted a hearing to examine the disputed evidence, and a hearing before an administrative law judge on the dispute was held on May 22 through May 24, 2007 and June 20, 2007.

The initial decision of the administrative law judge was issued September 6, 2007. The Presiding Judge generally found that the Transmission Agreement allows TEP to transmit power from the Deming Plant to Arizona but limits that transmission to 200 MW on any segment of the circuit and to non-firm service on the segment from Luna to Greenlee. The Company and TEP filed briefs on exceptions and replies to briefs on exceptions to the Initial Decision. In its brief on exceptions, TEP argued that it is entitled to a refund of the revenues the Company has received from TEP for transmission service to the Deming Plant during the pendency of these proceedings. In its response, the Company vigorously contested TEP's request for refunds. The Commission will issue a decision on the merits after review of the Initial Decision and the briefs on exceptions and replies to exceptions. While the Company believes that it will prevail on all points, the Company cannot predict the outcome of this case. During 2006 and 2007, TEP paid the Company $6.6 million for transmission service relating to the LEF. The Company has established a reserve for rate refund for $3.5 million related to this issue. If the FERC were to rule in TEP's favor, the Company may be required to refund all of the $6.6 million it has received from TEP for transmission service relating to the LEF and may lose the opportunity to

receive compensation from TEP for such transmission service in the future. An adverse ruling by the FERC could have a negative effect on the Company's results of operations.

RTOs. FERC's rule on RTOs ("Order 2000") strongly encourages, but does not require, public utilities to form and join RTOs. The Company is an active participant in the development of WestConnect. The Company has entered into a Memorandum of Understanding ("MOU") with ten other transmission owners that obligates the parties to participate in and commit resources to ongoing joint efforts, including involvement with stakeholders, customers, local, state and federal regulatory personnel, and other Western Grid transmission providers to identify, develop and implement cost-effective wholesale market enhancements on a voluntary, phased-in basis to add value in transmission accessibility, wholesale market efficiency and reliability for wholesale users of the Western Grid. These enhancements may ultimately include formation of an RTO. WestConnect will continue to work with the FERC and two other proposed RTOs in the west to achieve a seamless market structure. The Company comprises approximately 7% of WestConnect and cannot control the terms or timing of its development. WestConnect as an RTO will not be operational for several years.

Department of Energy. The DOE regulates the Company's exports of power to the CFE in Mexico pursuant to a license granted by the DOE and a presidential permit. The DOE has determined that all such exports over international transmission lines shall be made in accordance with Order No. 888, which established the FERC rules for open access.

The DOE is authorized to assess operators of nuclear generating facilities a share of the costs of decommissioning the DOE's uranium enrichment facilities and for the ultimate costs of disposal of spent nuclear fuel. See "Note C – Palo Verde – Spent Fuel Storage" for discussion of spent fuel storage and disposal costs.

Nuclear Regulatory Commission. The NRC has jurisdiction over the Company's licenses for Palo Verde and regulates the operation of nuclear generating stations to protect the health and safety of the public from radiation hazards. The NRC also has the authority to grant license extensions pursuant to the Atomic Energy Act of 1954, as amended.

Sales for Resale

The Company entered into a contract to sell up to 100 MW firm energy and 50 MW of contingent energy to Imperial Irrigation District ("IID") which began May 1, 2007 and continues through April 30, 2009. The contract also provides for the Company to sell up to 100 MW firm energy and 40 MW of contingent energy beginning May 1, 2009 through April 30, 2010. To ensure that power is available to meet the IID contract demand, the Company entered into a contract effective May 1, 2007 to purchase up to 100 MW of firm energy from CreditSuisse Energy, LLC. This contract provides for up to 100 MW of firm energy to be delivered at Palo Verde through April 30, 2010 and 50 MW of energy

delivered at Four Corners in the months of July through September 2007 and May through September for the years 2008 through 2010.

The Company provides up to 10 MW of firm capacity, associated energy, and transmission service to the Rio Grande Electric Cooperative pursuant to an ongoing contract which requires a two-year notice to terminate. In 2006 the Company provided RGEC with a notice of termination. Such termination will be effective as of March 31, 2008. The Company is discussing the provision of future electric service with RGEC.

C. Utility Plant, Palo Verde and Other Jointly-Owned Utility Plant

The table below presents the balance of each major class of depreciable assets at December 31, 2007 (in thousands):

	Gross Plant	Accumulated Depreciation	Net Plant
Nuclear production	$ 660,342	$ (174,024)	$ 486,318
Steam and other	279,930	(165,146)	114,784
Total production	940,272	(339,170)	601,102
Transmission	342,332	(217,024)	125,308
Distribution	647,516	(243,008)	404,508
General	91,690	(49,235)	42,455
Intangible	25,863	(9,989)	15,874
Total	$ 2,047,673	$ (858,426)	$ 1,189,247

Amortization of intangible plant (software) is provided on a straight-line basis over the estimated useful life of the asset (ranging from 3 to 10 years). The amortization expense for intangible plant was $3.3 million, $2.8 million and $1.9 million for 2007, 2006 and 2005, respectively. The table below presents the estimated amortization expense for the next five years (in thousands):

2008	$ 3,874
2009	3,502
2010	3,235
2011	1,654
2012	719

The Company owns a 15.8% interest in each of the three nuclear generating units and Common Facilities at Palo Verde, in Wintersburg, Arizona. The Palo Verde Participants include the Company and six other utilities: Arizona Public Service Company ("APS"), Southern California Edison Company ("SCE"), Public Service Company of New Mexico ("PNM"), Southern California Public Power

Authority, Salt River Project Agricultural Improvement and Power District ("SRP") and the Los Angeles Department of Water and Power.

Other jointly-owned utility plant includes a 7% interest in Units 4 and 5 at Four Corners Generating Station ("Four Corners") and certain other transmission facilities. A summary of the Company's investment in jointly-owned utility plant, excluding fuel inventories, at December 31, 2007 and 2006 is as follows (in thousands):

	December 31, 2007		December 31, 2006	
	Palo Verde	Other	Palo Verde	Other
Electric plant in service	$ 660,342	$ 193,574	$ 655,679	$ 190,200
Accumulated depreciation	(174,024)	(147,203)	(154,029)	(140,373)
Construction work in progress	75,035	5,051	33,222	3,181
Total	$ 561,353	$ 51,422	$ 534,872	$ 53,008

Palo Verde

The operation of Palo Verde and the relationship among the Palo Verde Participants is governed by the Arizona Nuclear Power Project Participation Agreement (the "ANPP Participation Agreement"). APS serves as operating agent for Palo Verde, and under the ANPP Participation Agreement, the Company has limited ability to influence operations and costs at Palo Verde. Pursuant to the ANPP Participation Agreement, the Palo Verde Participants share costs and generating entitlements in the same proportion as their percentage interests in the generating units, and each participant is required to fund its share of fuel, other operations, maintenance and capital costs. The Company's share of direct expenses in Palo Verde and other jointly-owned utility plants is reflected in fuel expense, other operations expense, maintenance expense, miscellaneous other deductions, and taxes other than income taxes in the Company's consolidated statements of operations. The ANPP Participation Agreement provides that if a participant fails to meet its payment obligations, each non-defaulting participant shall pay its proportionate share of the payments owed by the defaulting participant. Because it is impracticable to predict defaulting participants, the Company cannot estimate the maximum potential amount of future payment, if any, which could be required under this provision.

NRC. The NRC regulates the operation of all commercial nuclear power reactors in the United States, including Palo Verde. The NRC periodically conducts inspections of nuclear facilities and monitors performance indicators to enable the agency to arrive at objective conclusions about a licensee's safety performance. Based on this assessment information and using a cornerstone evaluation system, the NRC determines the appropriate level of agency response and oversight, including supplemental inspections and pertinent regulatory actions as necessary.

In October 2006, the NRC conducted an inspection of the Palo Verde emergency diesel generators after a Palo Verde Unit 3 emergency diesel generator did not activate during routine

inspections in July and September 2006. On February 22, 2007, the NRC issued a "white" finding (low to moderate safety significance) for this matter. Based upon this finding, coupled with a previous NRC "yellow" finding (substantial safety significance) relating to a 2004 matter involving Palo Verde's safety injection systems, the NRC placed Palo Verde Unit 3 in the "multiple/repetitive degraded cornerstone" column of the NRC's action matrix which has resulted in an enhanced NRC inspection regimen. This enhanced inspection regimen and resulting corrective actions has resulted in increased operating costs at the plant. Of the 104 commercial nuclear reactors in the United States regulated by the NRC, only Palo Verde Unit 3 was listed in the "multiple/repetitive degraded cornerstone" category as of the end of 2007. The Company is currently unable to predict the impact that the NRC's increased oversight may have on Palo Verde's operations and the cost of operations.

Decommissioning. Pursuant to the ANPP Participation Agreement and federal law, the Company must fund its share of the estimated costs to decommission Palo Verde Units 1, 2 and 3, including the Common Facilities, through the term of their respective operating licenses. The Company is required to maintain a minimum accumulation and a minimum funding level in its decommissioning account at the end of each annual reporting period during the life of the plant. The Company has established external trusts with an independent trustee which enable the Company to record a current deduction for federal income tax purposes of a portion of amounts funded. At December 31, 2007, the Company's decommissioning trust fund had a balance of $130.7 million and the Company was above its minimum funding level. The Company will continue to monitor the status of its decommissioning funds and adjust its deposits, if necessary, to remain at or above its minimum accumulation requirements in the future.

Decommissioning costs are estimated every three years based upon engineering cost studies performed by outside engineers retained by APS. In 2005, the Palo Verde Participants approved the 2004 Palo Verde decommissioning study ("2004 Study"). The 2004 Study estimated that the Company must fund approximately $335.7 million (stated in 2004 dollars) to cover its share of decommissioning costs. Although the 2004 Study was based on the latest available information, there can be no assurance that decommissioning cost estimates will not increase in the future or that regulatory requirements will not change. In addition, until a new low-level radioactive waste repository opens and operates for a number of years, estimates of the cost to dispose of low-level radioactive waste are subject to significant uncertainty. A study of decommissioning costs was performed in 2007 ("2007 Study"). Preliminary results of the 2007 Study indicate a reduction in decommissioning costs from the 2004 Study which, if adopted, will result in lower asset retirement obligations and lower expenses in the future. The 2007 Study is expected to be approved in the second quarter of 2008. See "Spent Fuel Storage" and "Disposal of Low-Level Radioactive Waste" below.

Spent Fuel Storage. The original spent fuel storage facilities at Palo Verde had sufficient capacity to store all fuel discharged from normal operation of all three Palo Verde units through 2003. Alternative on-site storage facilities and casks have been constructed to supplement the original facilities. In March 2003, APS began removing spent fuel from the original facilities as necessary, and placing it in special storage casks which will be stored at the new facilities until accepted by the DOE for

permanent disposal. The 2004 Study assumed that costs to store fuel on-site will become the responsibility of the DOE after 2037. APS believes that spent fuel storage or disposal methods will be available to allow each Palo Verde unit to continue to operate through the term of its operating license.

Pursuant to the Nuclear Waste Policy Act of 1982, as amended in 1987 (the "Waste Act"), the DOE is legally obligated to accept and dispose of all spent nuclear fuel and other high-level radioactive waste generated by all domestic power reactors. In accordance with the Waste Act, the DOE entered into a spent nuclear fuel contract with the Company and all other Palo Verde Participants. The DOE has previously reported that its spent nuclear fuel disposal facilities would not be in operation in the near future. Subsequent judicial decisions required the DOE to start accepting spent nuclear fuel by January 31, 1998. The DOE did not meet that deadline, and the Company cannot currently predict when spent fuel shipments to the DOE's permanent disposal site will commence.

The Company expects to incur significant costs for on-site spent fuel storage during the life of Palo Verde that the Company believes are the responsibility of the DOE. These costs are assigned to fuel requiring the additional on-site storage and amortized as that fuel is burned until an agreement is reached with the DOE for recovery of these costs. In December 2003, APS, in conjunction with other nuclear plant operators, filed suit against the DOE on behalf of the Palo Verde Participants to recover monetary damages associated with the delay in the DOE's acceptance of spent fuel. On February 28, 2007, APS served on the U.S. Department of Justice its "Initial Disclosure of Claimed Damages" of $93.4 million (the Company's portion being $14.8 million). This amount includes expenses associated with design, construction, loading, and operation of the Palo Verde independent spent fuel storage installation through December 2006. This amount represents costs incurred to ensure sufficient storage capacity for Palo Verde spent fuel that would not have been incurred had the DOE complied with its standard contract obligation to begin accepting spent fuel from the commercial nuclear power industry beginning in 1998. The Company is unable to predict the outcome of this matter at this time.

Disposal of Low-Level Radioactive Waste. Congress has established requirements for the disposal by each state of low-level radioactive waste generated within its borders. Arizona, California, North Dakota and South Dakota have entered into a compact (the "Southwestern Compact") for the disposal of low-level radioactive waste. California will act as the first host state of the Southwestern Compact, and Arizona will serve as the second host state. The construction and opening of the California low-level radioactive waste disposal site in Ward Valley has been delayed due to extensive public hearings, disputes over environmental issues and review of technical issues related to the proposed site. Palo Verde is projected to undergo decommissioning during the period in which Arizona will act as host for the Southwestern Compact. The opposition, delays, uncertainty and costs experienced in California demonstrate possible roadblocks that may be encountered when Arizona seeks to open its own waste repository. APS currently believes that interim low-level waste storage methods are or will be available to allow each Palo Verde unit to continue to operate and to store safely low-level waste until a permanent disposal facility is available.

Reactor Vessel Heads. In accordance with applicable NRC requirements, APS conducts regular inspections of reactor vessel heads at Palo Verde Units 1, 2 and 3. In an effort to reduce long-term operating costs at the station related to inspection of the reactor heads, related equipment, and possible repair costs, APS plans to replace reactor vessel heads at Palo Verde. Reactor vessel head replacement is scheduled to occur at Units 1, 2 and 3 in 2010, 2009 and 2009, respectively.

Liability and Insurance Matters. The Palo Verde participants have insurance for public liability resulting from nuclear energy hazards to the full limit of liability under federal law currently at $10.8 billion. This potential liability is covered by primary liability insurance provided by commercial insurance carriers in the amount of $300 million and the balance by an industry-wide retrospective assessment program. If a loss at a nuclear power plant covered by the programs exceeds the accumulated funds in the primary level of protection, the Company could be assessed retrospective premium adjustments on a per incident basis. Under federal law, the maximum assessment per reactor under the program for each nuclear incident is approximately $100.6 million, subject to an annual limit of $15 million. Based upon the Company's 15.8% interest in the three Palo Verde units, the Company's maximum potential assessment per incident for all three units is approximately $47.7 million, with an annual payment limitation of approximately $7.1 million.

The Palo Verde Participants maintain "all risk" (including nuclear hazards) insurance for property damage to, and decontamination of, property at Palo Verde in the aggregate amount of $2.75 billion, a substantial portion of which must first be applied to stabilization and decontamination. The Company has also secured insurance against portions of any increased cost of generation or purchased power and business interruption resulting from a sudden and unforeseen outage of any of the three units. The insurance coverage discussed in this and the previous paragraph is subject to certain policy conditions and exclusions. A mutual insurance company whose members are utilities with nuclear facilities issues these policies. If losses at any nuclear facility covered by this mutual insurance company were to exceed the accumulated funds for these insurance programs, the Company could be assessed retrospective premium adjustments of up to $11.5 million for the current policy period.

D. Accounting for Asset Retirement Obligations

The Company complies with SFAS No. 143, "Accounting for Asset Retirement Obligations" which primarily affects the accounting for the decommissioning of the Company's Palo Verde and Four Corners Stations and the method used to report the decommissioning obligation. The Company records the increase in the ARO due to the passage of time as an operating expense (accretion expense). As the DOE assumes responsibility for the permanent disposal of spent fuel, spent fuel costs have not been included in the ARO calculation. The Company has six external trust funds with an independent trustee which are legally restricted to settling its ARO at Palo Verde. The fair value of the funds at December 31, 2007 is $130.7 million.

A reconciliation of the Company's ARO liability recorded is as follows (in thousands):

	Years Ended December 31,		
	2007	2006	2005
ARO liability at beginning of year	$ 73,267	$ 66,997	$ 60,388
Liabilities incurred	–	–	2,719 (1)
Liabilities settled	(418)	–	–
Revisions to estimate	–	–	(1,767)
Accretion expense	6,860	6,270	5,657
ARO liability at end of year	$ 79,709	$ 73,267	$ 66,997

(1) Results from the implementation of FIN 47 (see discussion below).

The Company has transmission and distribution lines which are operated under various property easement agreements. If the easements were to be released, the Company may have a legal obligation to remove the lines; however, the Company has assessed the likelihood of this occurring as remote. The majority of these easements include renewal options which the Company routinely exercises.

The ARO liability for Palo Verde is based upon the estimated cost of decommissioning the plant from the 2004 Palo Verde decommissioning study. See Note C. The ARO liability is calculated by adjusting the estimated decommissioning costs for spent fuel storage and a profit margin and market-risk premium factor. The resulting costs are escalated over the remaining life of the plant and finally discounted using a credit-risk adjusted discount rate. Since the Company assumed an escalation rate of 3.6% and a credit-risk adjusted discount rate of 9.5% in the original calculation of the ARO liability, the ARO liability is less than the Company's share of the current estimated cost to decommission Palo Verde in 2004 dollars. As Palo Verde approaches the end of its estimated useful life, the difference between the ARO liability and future current cost estimates will narrow over time due to the accretion of the ARO liability.

SFAS No. 143 requires the Company to revise its previously recorded ARO for any changes in estimated cash flows. Any changes that result in an upward revision to estimated cash flows shall be treated as a new liability. Any downward revisions to the estimated cash flows result in a reduction to the previously recorded ARO. Since the 2004 study reflected a downward revision in the estimated cash flows for decommissioning costs from the 2001 study, the Company recorded a $1.8 million reduction to its ARO asset and liability in the third quarter of 2005. Accretion and depreciation expense related to the ARO decreased approximately $0.3 million annually as a result of this adjustment. An updated decommissioning study was performed in 2007 subject to approval of the Palo Verde Participants. Upon approval the ARO asset and liability will be adjusted to reflect the results of the 2007 study.

Effective December 31, 2005, the Company adopted FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations," ("FIN 47"). FIN 47 clarifies that the term "conditional" as used in SFAS No. 143, refers to a legal obligation to perform an asset retirement activity even if the timing and/or settlement are conditional on a future event that may or may not be within the control of an entity. Accordingly, the entity must record a liability for the conditional asset retirement obligation if the fair value of the obligation can be reasonably estimated. The adoption of FIN 47 primarily affected the accounting for the disposal obligations of the Company's fuel oil storage tanks, water wells, evaporative ponds and asbestos found at the Company's gas-fired generating plants. With the adoption of FIN 47 at December 31, 2005, the Company recognized an increase in its ARO of $2.7 million, an increase in net plant in service of $0.9 million, and a cumulative effect of accounting change resulting in a loss of $1.1 million, net of related taxes.

Amounts recorded under SFAS No. 143, including those under FIN 47, are subject to various assumptions and determinations such as (i) whether a legal obligation exists to remove assets; (ii) estimation of the fair value of the costs of removal; (iii) when final removal will occur; (iv) future changes in decommissioning cost escalation rates; and (v) the credit-adjusted interest rates to be utilized in discounting future liabilities. Changes that may arise over time with regard to these assumptions and determinations will change amounts recorded in the future as an expense for AROs. If the Company incurs or assumes any liability in retiring any asset at the end of its useful life without a legal obligation to do so, it will record such retirement costs as incurred.

E. Common Stock

Overview

The Company's common stock has a stated value of $1 per share, with no cumulative voting rights or preemptive rights. Holders of the common stock have the right to elect the Company's directors and to vote on other matters.

Long-Term Incentive Plans

On May 2, 2007, the Company's shareholders approved a stock-based long-term incentive plan (the "2007 Plan") and authorized the issuance of up to one million shares of common stock for the benefit of directors and employees. Under the plan, common stock may be issued through the award or grant of non-statutory stock options, incentive stock options, stock appreciation rights, restricted stock, bonus stock, performance stock, cash-based awards and other stock-based awards. Subject to applicable regulatory approvals, the Company may issue new shares, purchase shares on the open market, or issue shares from shares the Company has repurchased to meet the share requirements of these plans.

As discussed in Note A, the Company adopted SFAS No. 123 (revised) effective January 1, 2006. The Company adopted the "modified prospective application method" as provided for in SFAS No. 123 (revised) which provides for compensation expense related to unvested stock awards to be recognized prospectively. Under the modified prospective application method, the cumulative change in

compensation expense vested in prior periods is recognized in the period the new accounting standard was adopted.

Stock Options. Stock options have been granted at exercise prices equal to or greater than the market value of the underlying shares at the date of grant. The fair value for these options was estimated at the grant date using the Black-Scholes option pricing model. The options expire ten years from the date of grant unless terminated earlier by the Board of Directors (the "Board"). Stock options have not been granted since 2003.

The following table summarizes the transactions in the Company's stock options for 2007:

	Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value (In thousands)
Options outstanding at December 31, 2006	957,888	$ 12.45		
Options exercised	(384,000)	11.24		
Options outstanding at December 31, 2007	573,888	13.26	3.72	$ 7,063
Exercisable at December 31, 2007	553,888	13.28	3.64	6,807

The Company received approximately $4.3 million in cash for the 384,000 stock options exercised in 2007. During 2007, the Company realized $1.8 million in current tax benefits from the exercise of stock options. The intrinsic value of stock options exercised in 2007, 2006 and 2005 was $5.2 million, $5.6 million and $7.8 million, respectively. The fair value at grant date of options vested during 2007, 2006 and 2005 was $0.8 million, $1.2 million and $1.5 million, respectively. No options were forfeited or expired during 2007.

	Shares	Weighted Average Grant Date Fair Value
Nonvested options at December 31, 2006	140,000	$ 6.14
Options vested	(120,000)	6.37
Nonvested options at December 31, 2007	20,000	4.82

The Company recorded compensation cost of less than $0.1 million and $0.8 million in 2007 and 2006, respectively, related to the outstanding unvested stock option awards and the tax benefit and capitalized costs related to these compensation costs were less than $0.1 million and $0.3 million, respectively. On January 2, 2008, the remaining 20,000 stock options vested for which compensation expense was recognized by December 31, 2007. There is no remaining unrecognized compensation cost related to stock options. The weighted average aggregate fair value at grant date of these unvested stock options is $0.1 million.

Restricted Stock. The Company has awarded restricted stock under its long-term incentive plans. Restrictions from resale generally lapse and awards vest over periods of one to three years. The market value of vested restricted stock awards is expensed at the time of grant. The market value of the unvested restricted stock at the date of grant is amortized to expense over the restriction period. Compensation cost is not recognized for anticipated forfeitures prior to vesting. On May 18, 2007, the Company entered into an employment separation agreement with Gary Hedrick, the Company's former chief executive officer. As part of this separation agreement, Mr. Hedrick forfeited 100% of his unvested restricted shares. As a result, the Company revised its estimated forfeiture rates and reduced its compensation costs accordingly.

Approximately $1.7 million, $1.6 million and $1.4 million was charged to expense related to restricted stock awards in 2007, 2006 and 2005, respectively. The deferred tax benefit related to these expenses was $0.7 million, $0.6 million and $0.6 million for 2007, 2006 and 2005, respectively. The Company realized $0.2 million and $0.1 million of current tax benefits from the issuance of restricted stock in 2007 and 2006, respectively. No current tax benefits were realized for the tax deduction from restricted stock issuances in 2005 because the Company was in a tax net operating loss position. Any capitalized costs related to these expenses would be less than $0.1 million for all years.

The aggregate intrinsic value for restricted stock vested during 2007, 2006 and 2005 was $2.0 million, $1.9 million and $1.5 million, respectively. The fair value at grant date for restricted stock vested in 2007, 2006 and 2005 was $1.4 million, $1.6 million and $1.1 million, respectively. The outstanding restricted stock has remaining $1.3 million of unrecognized expense at December 31, 2007 that is expected to be recognized over the weighted average remaining contractual term of the outstanding restricted stock of approximately one year. The aggregate intrinsic value of the 119,403 outstanding restricted shares at December 31, 2007 was $3.1 million.

The following table summarizes the unvested restricted stock transactions for 2007:

	Total Shares	Weighted Average Grant Date Fair Value
Restricted shares outstanding at December 31, 2006.....	110,854	$ 19.32
Restricted stock awards	109,318	26.39
Lapsed restrictions and vesting.....	(77,019)	18.82
Forfeitures.....	(23,750)	21.33
Restricted shares outstanding at December 31, 2007.....	119,403	25.71

The weighted average fair values at grant date for restricted stock awarded during 2007, 2006 and 2005 are $26.39, $19.85 and $18.82, respectively.

The holder of a restricted stock award has rights as a shareholder of the Company, including the right to vote and, if applicable, receive cash dividends on restricted stock, except that certain restricted stock awards require any cash dividend on restricted stock to be delivered to the Company in exchange for additional shares of restricted stock of equivalent market value.

Performance Shares. The Company has granted performance share awards to certain officers under the Company's existing long-term incentive plans, which provide for issuance of Company stock based on the achievement of certain performance criteria over a three-year period. The payout varies between 0% to 200% of performance shares. On January 1, 2007, 58,650 performance shares were issued at the 150% performance level with a total cost of $0.7 million which had been expensed ratably between 2004 and 2006. The Company realized $0.3 million of current tax benefits from the issuance of performance shares in 2007. The requisite service period for these shares ended December 31, 2006, and the shares had an aggregate intrinsic value of $1.4 million. On January 1, 2008, 2009 and 2010, subject to meeting certain performance criteria, additional performance shares will be awarded. In accordance with SFAS No. 123 (revised), the Company will recognize the related compensation expense by ratably amortizing the grant date fair market value of awards over the requisite service period and the compensation expense will only be adjusted for forfeitures. The actual number of shares issued can range from zero to 292,682 shares.

The fair market value at the date of each separate grant of performance shares was based upon a Monte Carlo simulation. The Monte Carlo simulation reflected the structure of the performance plan which calculates the share payout on performance of the Company relative to a defined peer group over a three-year performance period based upon total return to shareholders. The fair market value was determined as the average payout of one million simulation paths discounted to the grant date using a risk-free interest rate based upon the constant maturity treasury rate yield curve at the grant date. The expected volatility of total return to shareholders is calculated in accordance with the plan's term structure and includes the volatilities of all members of the defined peer group.

The following table summarizes the outstanding performance share awards at the 100% performance level:

	Number Outstanding	Weighted Average Grant Date Fair Value
Performance shares outstanding at December 31, 2006	174,100	$ 19.92
Performance share awards	94,480	22.78
Performance shares lapsed and issued	(41,239)	18.46
Performance shares forfeited	(81,000)	20.69
Performance shares outstanding at December 31, 2007	146,341	21.75

The outstanding performance awards have remaining $1.1 million of unrecognized expense at December 31, 2007 that is expected to be recognized over the weighted average remaining contractual term of the awards of approximately 1.3 years. The aggregate intrinsic value of the 146,341 outstanding awards (based on 100% performance level) at December 31, 2007 was $3.7 million. The weighted average grant date fair value of performance shares awarded during the years 2007, 2006 and 2005 was $22.78, $18.37, and $22.55, respectively. The fair value of performance shares which vested in 2007 and 2006 was $0.7 million and $0.8 million, respectively, with an intrinsic value of $1.0 million and $0.8 million, respectively. No performance shares vested in 2005.

The Company recorded compensation expense related to performance shares of $0.4 million in 2007 and 2006, respectively. The compensation expense for 2007 and 2006 included cumulative adjustments. On May 18, 2007, the Company entered into an employment separation agreement with Gary Hedrick, the Company's former chief executive officer. As part of this separation agreement, Mr. Hedrick forfeited 100% of his unvested performance shares. As a result, the Company revised its forfeiture rates related to performance shares which resulted in a cumulative adjustment which reduced operating expense by $0.7 million pretax and $0.4 million after-tax. During the first quarter of 2006, the Company recorded a cumulative adjustment to operating expense related to 2004 and 2005 performance stock awards to reflect the implementation of SFAS No. 123 (revised) which reduced expense by $0.7 million pretax and $0.4 million after-tax. Deferred tax expense related to compensation expense in 2007 and 2006 was $0.1 million and less than $0.1 million, respectively.

Prior to implementing SFAS No. 123 (revised) the Company recognized compensation expense for performance share awards by ratably amortizing their fair market value at the end of the reporting period based on the Company's performance at that time over the performance cycles. The Company recorded compensation expense related to performance share awards of $1.5 million in 2005. The deferred tax related to these expenses was $0.6 million.

Common Stock Repurchase Program

Since the inception of the stock repurchase program in 1999, the Company has repurchased a total of approximately 19.3 million shares of its common stock at an aggregate cost of $269.4 million, including commissions. In September 2006, the Board authorized the repurchase of up to 2.3 million shares of the Company's outstanding common stock (the "2006 Plan"). During 2006 and 2007, the Company repurchased 4,055,158 shares of common stock under the 2006 Plan and under a previous plan approved by the Board in 2004 (the "2004 Plan") at an aggregate cost of $93.8 million. As of December 31, 2007, no shares remain available under the 2006 Plan or the 2004 Plan. In November 2007, the Board authorized the repurchase of up to an additional 2 million shares of the Company's outstanding common stock (the "2007 Plan"). No shares have been repurchased under the 2007 Plan. The Company may in the future make purchases of its common stock pursuant to the 2007 Plan in open market transactions at prevailing prices and may engage in private transactions where appropriate. The repurchased shares will be available for issuance under employee benefit and stock incentive plans, or may be retired.

Reconciliation of Basic and Diluted Earnings Per Share

The reconciliation of basic and diluted earnings per share before extraordinary item and cumulative effect of accounting change is presented below:

	Year Ended December 31, 2007		
	Income (In thousands)	Shares	Per Share
Basic earnings per share:			
Income before extraordinary item and cumulative effect of accounting change	$ 74,753	45,563,858	$ 1.64
Effect of dilutive securities:			
Unvested restricted stock	–	55,460	
Unvested performance awards	–	69,426	
Stock options	–	239,734	
Diluted earnings per share:			
Income before extraordinary item and cumulative effect of accounting change	$ 74,753	45,928,478	$ 1.63

	Year Ended December 31, 2006		
	Income (In thousands)	Shares	Per Share
Basic earnings per share:			
Income before extraordinary item and cumulative effect of accounting change	$ 61,387	47,663,890	$ 1.29
Effect of dilutive securities:			
Unvested restricted stock	–	57,459	
Unvested performance awards	–	87,147	
Stock options	–	355,571	
Diluted earnings per share:			
Income before extraordinary item and cumulative effect of accounting change	$ 61,387	48,164,067	$ 1.27

	Year Ended December 31, 2005		
	Income (In thousands)	Shares	Per Share
Basic earnings per share:			
Income before extraordinary item and cumulative effect of accounting change	$ 36,615	47,711,894	$ 0.77
Effect of dilutive securities:			
Unvested restricted stock	–	46,284	
Unvested performance awards	–	90,295	
Stock options	–	459,437	
Diluted earnings per share:			
Income before extraordinary item and cumulative effect of accounting change	$ 36,615	48,307,910	$ 0.76

No options were excluded from the computation of diluted earnings per share because the exercise price was greater than the average market price for the years ended December 31, 2007, 2006 and 2005.

F. Accumulated Other Comprehensive Income (Loss)

Accumulated other comprehensive income (loss) consists of the following components (in thousands):

	Net Unrealized Gains (Losses) on Marketable Securities	Unrecognized Pension and Postretirement Benefit Costs	Net Losses on Cash Flow Hedges	Accumulated Other Comprehensive Income (Loss)
Balance at December 31, 2004	$ 6,355	$ (16,908)	$ –	$ (10,553)
Other comprehensive loss	(2,359)	(6,128)	(22,296)	(30,783)
Income tax benefit	472	2,299	8,398	11,169
Balance at December 31, 2005	4,468	(20,737)	(13,898)	(30,167)
Other comprehensive income	9,466	16,923	263	26,652
Income tax expense	(1,893)	(6,348)	(99)	(8,340)
SFAS No. 158 adoption, net of tax of $3,879	–	(6,461)	–	(6,461)
Balance at December 31, 2006	12,041	(16,623)	(13,734)	(18,316)
Other comprehensive income	4,152	41,256	278	45,686
Income tax expense	(830)	(18,037)	(104)	(18,971)
Adjustment for tax effect of SFAS No. 158	–	5,141	–	5,141
Balance at December 31, 2007	$ 15,363	$ 11,737	$ (13,560)	$ 13,540

G. Long-Term Debt and Financing Obligations

Outstanding long-term debt and financing obligations are as follows:

	December 31, 2007	December 31, 2006
	(In thousands)	
Long-Term Debt:		
Pollution Control Bonds (1):		
2005 Series B refunding bonds, due 2040	$ 63,500	$ 63,500
4.80% 2005 Series A refunding bonds, due 2040	59,235	59,235
2005 Series C refunding bonds, due 2040	37,100	37,100
4.00% 2002 Series A refunding bonds, due 2032	33,300	33,300
Senior Notes (2):		
Senior Notes, net of discount, due 2035	397,759	397,730
Total long-term debt	590,894	590,865
Financing Obligations:		
Nuclear fuel ($18,798 due in 2008) (3)	83,015	46,240
Total long-term debt and financing obligations	673,909	637,105
Current Portion (amount due within one year)	(18,798)	(20,975)
	$ 655,111	$ 616,130

(1) Pollution Control Bonds

The Company has four series of tax exempt Pollution Control Bonds in an aggregate principal amount of approximately $193.1 million. On August 1, 2005, the Company reissued three series of pollution control bonds which were the 2005 Series B bonds for $63.5 million, the 2005 Series A bonds for $59.2 million and the 2005 Series C bonds for $37.1 million. The 2005 Series A $59.2 million bonds which mature in 2040, were reissued with a fixed interest rate of 4.80% and an effective interest rate of 5.27% after considering related insurance and issuance costs. The 2005 Series B $63.5 million and 2005 Series C $37.1 million bonds, which also mature in 2040, were reissued with a variable rate that is repriced weekly, 5.35% and 4.91% at December 31, 2007, respectively. These bonds are insured by FGIC whose bond ratings have recently been downgraded by all the major rating agencies thereby calling into question FGIC's claims paying ability in the event of default by the Company. As a result, the Company has experienced increased yields and resulting interest expense for the PCBs. Although there has not yet been a failed auction of the PCBs, if one were to occur the Company would be required to pay a default interest rate of 15%. The Company also remarketed the 2002 Series A $33.3 million of pollution control bonds which bear a fixed interest rate of 4.00% until August 1, 2012 which is the date the bonds are due to be remarketed. The effective interest rate for these bonds is 4.70% after considering related insurance and issuance costs. The interest rate will remain at its current fixed interest rate until remarketing in August 2012.

(2) Senior Notes

The Company filed a shelf registration statement on Form S-3 with the Securities and Exchange Commission which became effective in May 2005. The shelf registration statement enables the Company to offer and issue debt securities, first mortgage bonds, shares of stock and certain other securities from time to time in one or more offerings of up to $1.0 billion.

In May 2005, the Company issued $400.0 million aggregate principal amount of its 6% Senior Notes due May 15, 2035 (the "Notes") under its shelf registration statement. The proceeds from the issuance of the Notes of $397.7 million (net of a $2.3 million discount) were used to fund the retirement of the Company's first mortgage bonds.

(3) Nuclear Fuel and Working Capital Financing

The Company has available a $200 million credit facility for a five-year term ending April 2011. The credit facility was expanded under terms of the facility from $150 million to $200 million in July 2007 due to increased volatility in the nuclear fuel market. The credit facility provides for up to $120 million for the financing of nuclear fuel, which is accomplished through a trust that borrows under the facility to acquire and process the nuclear fuel. The Company is obligated to repay the trust's borrowings with interest. In the Company's financial statements, the assets and liabilities of the trust are reported as assets and liabilities of the Company. Any amounts not borrowed by the trust may be borrowed by the Company for working capital needs. The weighted average interest rate on the credit facility was 5.59% as of December 31, 2007.

The $200 million credit facility requires compliance with certain total debt and interest coverage ratios. The Company was in compliance with these requirements throughout 2007. No amounts are currently outstanding on this facility for working capital needs.

As of December 31, 2007, the scheduled maturities for the next five years of long-term debt and financing obligations are as follows (in thousands):

2008	$ –
2009	–
2010	–
2011	–
2012	33,300

The table above does not reflect future obligations and maturities related to nuclear fuel financing obligations.

H. Income Taxes

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and liabilities at December 31, 2007 and 2006 are presented below (in thousands):

	December 31,	
	2007	2006
Deferred tax assets:		
Alternative minimum tax credit carryforward	$ 42,495	$ 50,172
Pensions and benefits	40,860	53,962
Asset retirement obligation	27,898	25,644
Other	19,244	20,094
Total gross deferred tax assets	130,497	149,872
Deferred tax liabilities:		
Plant, principally due to depreciation and basis differences	(240,721)	(232,905)
Decommissioning	(33,896)	(31,118)
Deferred fuel	(9,694)	(16,554)
Other	(15,049)	(13,167)
Total gross deferred tax liabilities	(299,360)	(293,744)
Net accumulated deferred income taxes	$ (168,863)	$ (143,872)

Based on the average annual book income before taxes for the prior three years, excluding the effects of extraordinary and unusual or infrequent items, the Company believes that the net deferred tax assets will be fully realized at current levels of book and taxable income.

The Company recognized income taxes as follows (in thousands):

	Years Ended December 31,		
	2007	2006	2005
Income tax expense:			
Federal:			
Current	$ 19,579	$ 7,973	$ (4,909)
Deferred	10,499	27,496	23,046
Total federal income tax	30,078	35,469	18,137
State:			
Current	4,496	1,007	(1,788)
Deferred	(107)	(6,845)	1,583
Total state income tax	4,389	(5,838)	(205)
Total income tax expense	34,467	29,631	17,932
Tax expense classified as extraordinary gain on re-application of SFAS No. 71	–	(3,565)	–
Tax benefit (expense) classified as cumulative effect of accounting change	–	–	657
Total income tax expense before extraordinary item and cumulative effect of accounting change	$ 34,467	$ 26,066	$ 18,589

The current federal income tax expense for 2007 results primarily from increased pretax income and certain permanent differences. The current federal income tax expense for 2006 results primarily from the accrual of alternative minimum tax ("AMT"). The current income tax expense for 2005 results primarily from a reversal of AMT for prior years as a result of increased tax deductions due to several method changes primarily related to tax depreciation and repair allowances. Deferred federal income tax for 2007 includes an offsetting AMT benefit of $7.1 million. Deferred federal income tax includes an offsetting AMT expense of $8.4 million and $6.7 million for 2006 and 2005 respectively. The reduction in deferred state income taxes in 2006 is a result of legislation approved in Texas revamping the state franchise (income) tax. The tax legislation changes the franchise tax from a tax based upon either taxable capital or taxable income to a 1% tax on taxable margins. The revised franchise tax is effective for tax payments in 2008 based upon 2007 taxable margin. The Company's taxable margin is based upon revenues taxable for federal income tax purposes less cost of goods sold which includes all costs of producing electricity, but does not include post-production costs. Even with the lower tax rate, the expansion of the tax base resulted in higher franchise tax expense beginning in 2007.

For accounting purposes, the revised franchise tax is an income tax subject to the requirements of SFAS No. 109, "Accounting for Income Taxes". SFAS No. 109 requires that deferred tax assets and liabilities be adjusted for changes in tax law in the period of change. As a result, the Company recorded a $6.2 million reduction in its net deferred tax liability in the second quarter of 2006 and a corresponding reduction in income tax expense. The adjustment to the net deferred income tax liability includes: (i) a reduction of $2.7 million in net Texas deferred income tax liabilities associated with temporary differences that will not reverse in the future under the revised franchise tax calculation; (ii) a reduction of $6.8 million in net Texas deferred income tax liabilities for the change in tax rate from 4.5% to 1% effective in 2007; and (iii) an increase of $3.3 million in deferred federal income tax liabilities to reflect the change in deferred federal income taxes associated with deferred Texas franchise taxes.

Income tax provisions differ from amounts computed by applying the statutory federal income tax rate of 35% to book income before federal income tax as follows (in thousands):

	Years Ended December 31,		
	2007	2006	2005
Federal income tax expense computed on income at statutory rate	$ 38,227	$ 33,938	$ 18,709
Difference due to:			
State taxes, net of federal benefit	2,852	2,184	(133)
Deferred tax adjustment for change in Texas franchise (income) tax	–	(6,174)	–
Allowance for equity funds used during construction	(2,398)	–	–
Permanent tax differences	(4,091)	(1,670)	323
Other	(123)	1,353	(967)
Total income tax expense	34,467	29,631	17,932
Tax expense classified as extraordinary gain on re-application of SFAS No. 71	–	(3,565)	–
Tax benefit (expense) classified as cumulative effect of accounting change	–	–	657
Total income tax expense before extraordinary item and cumulative effect of accounting change	$ 34,467	$ 26,066	$ 18,589
Effective income tax rate	31.6%	31.0%	33.5%

As of December 31, 2007, the Company had $42.5 million of AMT credit carryforwards that have an unlimited life.

The Company files income tax returns in the U.S. federal jurisdiction and in the states of Texas, New Mexico and Arizona. The Company is no longer subject to tax examination by the taxing authorities in the federal or state jurisdictions for years prior to 1998. The Company's federal tax returns for the years 1999 through 2004 have been examined by the IRS. The Company is currently under audit for 2005. On June 12, 2007, the Company received the IRS notice of proposed deficiency for the tax years 1999 through 2004. A previous IRS notice of proposed deficiency had been received for the years 1999 through 2002 in 2004. The primary audit adjustments proposed by the IRS related to (i) whether the Company was entitled to currently deduct payments related to the repair of the Palo Verde Unit 2 steam generators or whether these payments should be capitalized and depreciated and (ii) whether the Company was entitled to currently deduct payments related to the dry cask storage facilities for spent nuclear fuel or whether these payments should be capitalized and depreciated. A tax deficiency was also received proposing to include in taxable income capital costs paid by third parties for construction of a switchyard. The third parties have indemnified the Company against any tax liability associated with the switchyard. The proposed IRS adjustments would affect the timing of these deductions not their ultimate deductibility for federal tax purposes. The Company protested the audit adjustments through

administrative appeals. The Company believes that its treatment of the payments is supported by substantial legal authority.

A deficiency notice relating to the Company's 1998 through 2003 income tax returns in Arizona contests a pollution control credit and the payroll apportionment factor. The Company is contesting these adjustments.

The Company adopted FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes," ("FIN 48") on January 1, 2007. FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. As a result of the implementation of FIN 48, the Company recognized a $1.9 million decrease in the liability for unrecognized tax benefits, which was accounted for as an increase to the January 1, 2007, balance of retained earnings. A reconciliation of the December 31, 2006 and December 31, 2007 amount of unrecognized tax benefits is as follows:

	Year Ended December 31, 2007 (In millions)
Balance at December 31, 2006	$ 6.8
Additions based on tax positions related to the current year	2.0
Additions for tax positions of prior years	0.1
Reductions for tax positions of prior years	(0.4)
Balance at December 31, 2007	$ 8.5

The Company has determined that the ultimate deductibility of the federal tax positions as of December 31, 2007 are "highly certain", as such term is defined in FIN 48, but the timing of such deductibility is uncertain. Because of the impact of deferred tax accounting, the disallowance of the shorter deductibility period does not change the amount of tax expense other than associated interest and penalties. However, the timing of cash payments to the federal taxing authority would be affected. An unrecognized tax position of $0.2 million associated with state income taxes has been recognized as a reduction in income tax expense.

The Company recognizes in tax expense interest and penalties related to tax benefits that have not been recognized. During the years ended December 31, 2007 and December 31, 2006, the Company recognized approximately $0.7 million and $0.1 million, respectively, in interest. The Company had approximately $2.5 million and $3.6 million for the payment of interest and penalties accrued at December 31, 2007 and December 31, 2006, respectively.

I. Commitments, Contingencies and Uncertainties

Federal Regulatory Matters

Transmission Dispute with Tucson Electric Power Company ("TEP"). In January 2006, the Company filed a complaint with the FERC to interpret the terms of a Power Exchange and Transmission Agreement (the "Transmission Agreement") entered into with TEP in 1982. TEP filed a complaint with the FERC one day later raising virtually identical issues. TEP claimed that, under the Transmission Agreement, it was entitled to up to 400 MW of firm transmission rights on the Company's transmission system that would enable it to transmit power from a new generating station (the Luna Energy Facility ("LEF") located near Deming, New Mexico) to Springerville or Greenlee in Arizona. The Company asserted that TEP's rights under the Transmission Agreement do not include transmission rights necessary to transmit such power as contemplated by TEP and that TEP must acquire any such rights in the open market from the Company at applicable tariff rates or from other transmission providers. On April 24, 2006, the FERC ruled in the Company's favor, finding that TEP does not have the transmission rights under the Transmission Agreement to transmit power from the LEF to Arizona. The ruling was based on written evidence presented and without an evidentiary hearing. TEP's request for a rehearing of the FERC's decision was granted in part and denied in part in an order issued October 4, 2006. The October 4 order granted a hearing to examine the disputed evidence, and a hearing before an administrative law judge on the dispute was held on May 22 through May 24, 2007 and June 20, 2007.

The initial decision of the administrative law judge was issued September 6, 2007. The Presiding Judge generally found that the Transmission Agreement allows TEP to transmit power from the Deming Plant to Arizona but limits that transmission to 200 MW on any segment of the circuit and to non-firm service on the segment from Luna to Greenlee. The Company and TEP filed briefs on exceptions and replies to briefs on exceptions to the Initial Decision. In its brief on exceptions, TEP argued that it is entitled to a refund of the revenues the Company has received from TEP for transmission service to the Deming Plant during the pendency of these proceedings. In its response, the Company vigorously contested TEP's request for refunds. The Commission will issue a decision on the merits after review of the Initial Decision and the briefs on exceptions and replies to exceptions. While the Company believes that it will prevail on all points, the Company cannot predict the outcome of this case. During 2006 and 2007, TEP paid the Company $6.6 million for transmission service relating to the LEF. The Company has established a reserve for rate refund for $3.5 million related to this issue. If the FERC were to rule in TEP's favor, the Company may be required to refund all of the $6.6 million it has received from TEP for transmission service relating to the LEF and may lose the opportunity to receive compensation from TEP for such transmission service in the future. An adverse ruling by the FERC could have a negative effect on the Company's results of operations.

Power Contracts

The Company had entered into the following significant agreements with various counterparties for forward firm purchases and sales of electricity:

Type of Contract	Quantity	Term
Power Purchase and Sale Agreement	100 MW	2006 through 2021
Purchase Capacity	133 MW	2006 through September 2009
Purchase On-peak Energy	100 MW	2008
Sale On-peak Energy	100 MW	2008
Power Sale Agreement	100 MW	May 2007 through April 2010
Power Purchase Agreement	100 MW	May 2007 through April 2010

In addition to the above transactions, the Company has also entered into several agreements with various counterparties for the forward firm purchases and sales of electricity during the first quarter of 2008:

Type of Contract	Quantity	Term
Purchase Off-Peak Energy	225 MW	1st Quarter 2008
Sale Off-Peak Energy	225 MW	1st Quarter 2008

To supplement its own generation and operating reserves, the Company engages in firm and non-firm power purchase arrangements which may vary in duration and amount based on evaluation of the Company's resource needs and the economics of the transactions. In 2004, the Company entered into a 20-year contract, beginning in 2006, for the purchase of up to 133 MW of capacity and associated energy from SPS. This contract includes a demand charge, fuel charge, variable operations and maintenance charge, and a transmission charge. The contract provides that, in the event the transactions thereunder are subject to adverse regulatory action, the affected party may initiate discussions with the other party to assess whether modifications to the agreement may be appropriate. If the parties are unable to reach a mutually satisfactory resolution within six months, either party may terminate the contract by providing not less than two years' prior written notice to the other party.

The Company previously received notice from SPS that SPS had been subject to adverse regulatory action by the Texas Commission regarding transactions under the contract and that SPS wished to exercise its right to terminate the contract early. As a result, on January 29, 2008, the Company and SPS entered into an amendment to the contract and agreed that the contract will terminate on September 30, 2009.

In June 2006, the Company began exchanging up to 100 MW of capacity and associated energy with Phelps Dodge Energy. The contract provides for Phelps Dodge to deliver energy to the Company from its ownership interest in the Luna Energy Facility, an approximate 570 MW natural gas fired combined cycle generation facility located in Luna County, New Mexico and for the Company to deliver

a like amount of energy at the Greenlee delivery point. The Company may purchase up to 100 MW at a specified price at times when energy is not exchanged. The agreement was approved by the FERC and continues through December 31, 2021.

The Company entered into a contract to sell up to 100 MW of firm energy and 50 MW of contingent energy to Imperial Irrigation District ("IID") which began May 1, 2007 and continues through April 30, 2009. The contract also provides for the Company to sell up to 100 MW of firm energy and 40 MW of contingent energy beginning May 1, 2009 through April 30, 2010. To ensure that power is available to meet the IID contract demand, the Company entered into a contract effective May 1, 2007 to purchase up to 100 MW of firm energy from CreditSuisse Energy, LLC. This contract provides for up to 100 MW of firm energy to be delivered at Palo Verde through April 30, 2010 and 50 MW of energy delivered at Four Corners in the months of July through September in 2007 and May through September for the years 2008 through 2010.

Environmental Matters

The Company is subject to regulation with respect to air, soil and water quality, solid waste disposal and other environmental matters by federal, state, tribal and local authorities. Those authorities govern current facility operations and have continuing jurisdiction over facility modifications. Failure to comply with these environmental regulatory requirements can result in actions by regulatory agencies or other authorities that might seek to impose on the Company administrative, civil, and/or criminal penalties. In addition, unauthorized releases of pollutants or contaminants into the environment can result in costly cleanup obligations that are subject to enforcement by regulatory agencies.

These laws and regulations are subject to change and, as a result of those changes, the Company may face additional capital and operating costs to comply. For example, recent developments suggest a growing likelihood of future regulation relating to climate change and greenhouse gas emissions. At the federal level, Congress continues to hold many hearings relating to climate change issues and many bills have been introduced to impose regulation through regulatory schemes including a "cap and trade" program. The United States Supreme Court has found carbon dioxide, one of the principal greenhouse gases, to be a "pollutant" under the Clean Air Act, increasing the possibility that the U.S. Environmental Protection Agency will begin to regulate these emissions even in the absence of further action by Congress. In addition, the State of New Mexico, where the Company operates one facility and has an interest in another facility, has joined with California and several other states in the Western Regional Climate Action Initiative and is pursuing initiatives to reduce greenhouse gas emissions in the state. The Company is monitoring these developments and how regulation may affect it. If the United States or individual states in which the Company operates were to regulate greenhouse gas emissions, the Company's fossil fuel generation assets are likely to face additional costs for monitoring, reporting, controlling, or offsetting these emissions.

Another way in which environmental matters may impact the Company's operations and business is the implementation of the U.S. Environmental Protection Agency's Clean Air Interstate Rule which, as applied to the Company, may result in a requirement that it substantially reduce emissions of nitrogen oxides from its power plants in Texas and/or purchase allowances representing other parties' emissions

reductions starting in 2009. These requirements become more stringent in 2015, and are anticipated to require even further emissions reductions or additional allowance purchases.

The Company takes these regulatory matters seriously and is monitoring these issues so that the Company is best able to effectively adapt to any such changes. Because the Company's generating portfolio has a carbon footprint that compares favorably with other power generating companies, the Company believes such regulations would not impose greater relative burdens on the Company than on most other electric utilities. Environmental regulations like these can change rapidly and those changes are often difficult to predict. While the Company strives to prepare for and implement actions necessary to comply with changing environmental regulations, substantial expenditures may be required for the Company to comply with such regulations in the future and, in some instances, those expenditures may be material. The Company believes it is impossible at present to meaningfully quantify the costs of these potential impacts.

The Company analyzes the costs of its obligations arising from environmental matters on an ongoing basis and believes it has made adequate provision in its financial statements to meet such obligations. As a result of this analysis, the Company has a provision for environmental remediation obligations of approximately $1.4 million as of December 31, 2007, which amounts are related to compliance with federal and state environmental standards. However, unforeseen expenses associated with environmental compliance or remediation may occur and could have a material adverse effect on the future operations and financial condition of the Company.

The Company incurred the following expenditures to comply with federal environmental statutes (in thousands):

	Years Ended December 31,		
	2007	2006	2005
Clean Air Act	$ 1,808	$ 1,203	$ 1,106
Clean Water Act (1)	1,293	2,004	1,708

(1) Includes a $0.5 million adjustment reducing the estimated costs of remediation at the Rio Grande and Copper generating stations and $1.1 million in remediation costs for the twelve months ended December 31, 2007 and 2005, respectively.

Along with many other companies, the Company received from the Texas Commission on Environmental Quality ("TCEQ") a request for information in 2003 in connection with environmental conditions at a facility in San Angelo, Texas that was operated by the San Angelo Electric Service Company ("SESCO"). In November 2005, TCEQ proposed the SESCO site for listing on the registry of Texas state superfund sites and mailed notice to more than five hundred entities, including the Company, indicating that TCEQ considers each of them to be "potentially responsible parties" at the SESCO site. The Company received from the SESCO working group of potentially responsible parties a settlement offer in May 2006 for remediation and other expenses expected to be incurred in connection with the SESCO site. The Company's position is that any liability it may have related to the SESCO site was discharged in the

Company's bankruptcy. At this time, the Company has not agreed to a settlement or to otherwise participate in the cleanup of the SESCO site and is unable to predict the outcome of this matter. While the Company has no reason at present to believe that it will incur material liabilities in connection with the SESCO site, it has accrued $0.3 million for potential costs related to this matter.

On September 26, 2006, the Secretary of the New Mexico Environment Department issued a Compliance Order concerning the Company's Rio Grande Generating Station, located in Dona Ana County, New Mexico. The Compliance Order alleges that, on approximately 650 occasions between May 2000 and September 2005, the Rio Grande Generating Station emitted sulfur dioxide, nitrogen oxides or carbon monoxide in excess of its permitted emission rates and failed to properly report these allegedly excess emissions. The Compliance Order asserts a statutory authority to seek a civil penalty of up to $15,000 per violation for each of the violations alleged. The Company disputes the allegations made and has requested a hearing before the New Mexico Environment Department on the matter. While the Company cannot predict the outcome of this matter, it believes these emissions did not violate applicable legal standards and that penalties, if any, should not involve a material liability.

On April 4, 2007, the Company submitted its application for a New Source Review Air Quality Permit/Prevention of Significant Deterioration ("PSD") permit to the TCEQ for the new natural-gas electric generating units to be located at its existing Newman plant site in the City of El Paso ("Newman Unit 5"). The Company expects to receive approval of its PSD application in the second quarter of 2008. Additional environmental permits other than the PSD are not required to begin construction of these new generating units because Newman Unit 5 will be constructed at an existing plant site and other permits are currently in place which will encompass Newman Unit 5.

In May 2007, the Environmental Protection Agency finalized a new federal implementation plan which addresses emissions at the Four Corners Station in northwestern New Mexico of which the Company owns a 7% interest in Units 4 and 5. Arizona Public Service, the Four Corners operating agent, has filed suit against the Environmental Protection Agency relating to this new federal implementation plan in order to resolve issues involving operating flexibility for emission opacity standards. The Company cannot predict the outcome of the suit filed against the Environmental Protection Agency or whether compliance with the new requirements could have an adverse effect on its capital and operating costs.

Except as described herein, the Company is not aware of any other active investigation of its compliance with environmental requirements by the Environmental Protection Agency, the TCEQ or the New Mexico Environment Department which is expected to result in any material liability. Furthermore, except as described herein, the Company is not aware of any unresolved, potentially material liability it would face pursuant to the Comprehensive Environmental Response, Comprehensive Liability Act of 1980, also known as the Superfund law.

MiraSol Warranty Obligations

MiraSol is an energy services subsidiary which offered a variety of services to reduce energy use and/or lower energy costs. MiraSol was not a power marketer. On July 19, 2002, all sales activities of MiraSol ceased. MiraSol remains a going concern in order to satisfy current contracts and warranty and service obligations on previously installed projects. As of December 31, 2007, the Company has a reserve for warranty claims in the amount of approximately $1.0 million. Accruals, charges and balances for the reserve for warranty claims are as follows:

	Years Ended December 31,		
	2007	2006	2005
Balance at beginning of year	$ 1,785	$ 1,288	$ 1,305
Accrual of warranty costs	–	500	–
Charges for work performed	–	(3)	(17)
Liabilities settled	(800)	–	–
Balance at end of year	$ 985	$ 1,785	$ 1,288

While no other probable warranty liabilities have been identified at this time, if it is determined at a future date that MiraSol has further obligations to any customer, and contributions from MiraSol, its subcontractors or any other third party are insufficient to honor the warranty obligations, the Company intends to honor any such warranty obligations after making appropriate regulatory filings, if any.

Lease Agreements

The Company has operating leases for administrative offices and certain warehouse facilities. The administrative offices lease has an 11-year term ending May 31, 2018. The fixed minimum lease payments are $1.7 million annually. On February 8, 2008, the Company exercised its right of first refusal in the lease agreement to purchase this office building. All obligations previously incurred relating to this lease were terminated. The warehouse facilities lease expires in December 2009 and has three concurrent renewal options of one year each. The lease payments are $0.3 million annually. The lease agreements do not impose any restrictions relating to issuance of additional debt, payment of dividends or entering into other lease arrangements. The Company has no significant capital lease agreements.

The Company's total annual rental expense related to operating leases was $2.0 million, $1.7 million and $1.1 million for 2007, 2006 and 2005, respectively. As of December 31, 2007, the Company's minimum future rental payments for the next five years are as follows (in thousands):

2008	$ 2,739
2009	2,301
2010	1,830
2011	1,762
2012	1,714

J. Litigation

The Company is a party to various legal actions. In many of these matters, the Company has excess casualty liability insurance that covers the various claims, actions and complaints. Based upon a review of these claims and applicable insurance coverage, to the extent that the Company has been able to reach a conclusion as to its ultimate liability, it believes that none of these claims will have a material adverse effect on the financial position, results of operations or cash flows of the Company.

On June 7, 2004, the City of Tacoma filed suit against the Company and other defendants in the United States District Court for the Western District of Washington *(City of Tacoma v. American Electric Power Service Corp., et al.,* C04-5325RBL). This complaint sought civil damages (including treble damages) from the Company and the other defendants for violations of certain antitrust provisions under the Sherman Act. This matter was filed in the United States District Court for the Western District of Washington and on February 11, 2005, the Court granted the Company's motion to dismiss the case. The City of Tacoma filed a notice of appeal with the U.S. Court of Appeals for the Ninth Circuit. On March 20, 2007, the Ninth Circuit entered an order dismissing the appeal pursuant to a stipulation of the parties. The dismissal is final and no further appeal may be filed.

On May 5, 2004, Wah Chang, a specialty metals manufacturer which operates a plant in Oregon, filed suit against the Company and other defendants in the United States District Court for the District of Oregon. *(Wah Chang v. Avista Corporation, et al.,* No. 04-619AS). The complaint also makes substantially the same allegations as were made in *City of Tacoma* and seeks the same types of damages. This matter was transferred to the same court that heard and dismissed the *City of Tacoma* lawsuit and on February 11, 2005, the Court granted the Company's motion to dismiss the case. Wah Chang filed notice of appeal with the U.S. Court of Appeals for the Ninth Circuit, and in November 2007, the Ninth Circuit upheld the dismissal of the suit. Wah Chang filed a motion for rehearing of the appeal, and on January 15, 2008, the Ninth Circuit denied Wah Chang's motion. While the Company believes that this matter is without merit and intends to defend itself vigorously in any further appeal by Wah Chang to the U.S. Supreme Court, the Company is unable to predict the outcome or range of possible loss.

See "Note B" for discussion of the effects of government legislation and regulation on the Company.

K. Employee Benefits

Retirement Plans

The Company's Retirement Income Plan (the "Retirement Plan") covers employees who have completed one year of service with the Company and work at least a minimum number of hours each year. The Retirement Plan is a qualified noncontributory defined benefit plan. Upon retirement or death of a vested plan participant, assets of the Retirement Plan are used to pay benefit obligations under the

Retirement Plan. Contributions from the Company are at least the minimum funding amounts required by the IRS under provisions of the Retirement Plan, as actuarially calculated. The assets of the Retirement Plan are invested in equity securities, debt securities and cash equivalents and are managed by professional investment managers appointed by the Company.

The Company has two non-qualified retirement income plans that are non-funded defined benefit plans. One plan covers certain former employees of the Company, and the other plan, an excess benefit plan adopted during 2004, covers certain active and former employees of the Company. The benefit cost for the non-qualified retirement income plans are based on substantially the same actuarial methods and economic assumptions as those used for the Retirement Plan. On December 31, 2006, the Company adopted SFAS No. 158 "Employer's Accounting for Defined Benefit Pension and Other Postretirement Plans", which amended SFAS No. 87 and SFAS No. 132R. The Company uses a measurement date of December 31 for its retirement plans; therefore, there were no adjustments related to a change in measurement date as a result of the adoption of SFAS No. 158.

The obligations and funded status of the plans are presented below (in thousands):

	December 31,			
	2007		2006	
	Retirement Income Plan	Non-Qualified Retirement Income Plans	Retirement Income Plan	Non-Qualified Retirement Income Plans
Change in projected benefit obligation:				
Benefit obligation at end of prior year	$ 182,222	$ 22,112	$ 181,191	$ 23,523
Service cost	5,455	179	5,466	141
Interest cost	10,794	1,263	9,892	1,236
Actuarial gain	(12,153)	(1,534)	(9,043)	(1,085)
Benefits paid	(6,017)	(1,623)	(5,284)	(1,703)
Benefit obligation at end of year	180,301	20,397	182,222	22,112
Change in plan assets:				
Fair value of plan assets at end of prior year	146,425	–	123,492	–
Actual return on plan assets	16,620	–	16,217	–
Employer contribution	12,000	1,623	12,000	1,703
Benefits paid	(6,017)	(1,623)	(5,284)	(1,703)
Fair value of plan assets at end of year	169,028	–	146,425	–
Funded status at end of year	$ (11,273)	$ (20,397)	$ (35,797)	$ (22,112)

Amounts recognized in the Company's consolidated balance sheets consist of the following (in thousands):

	December 31,			
	2007		2006	
	Retirement Income Plan	Non-Qualified Retirement Income Plans	Retirement Income Plan	Non-Qualified Retirement Income Plans
Current liabilities	$ –	$ (1,582)	$ –	$ (1,649)
Noncurrent liabilities	(11,273)	(18,815)	(35,797)	(20,463)
Total	$ (11,273)	$ (20,397)	$ (35,797)	$ (22,112)

The accumulated benefit obligation for all retirement plans was $164.7 million and $172.7 million at December 31, 2007 and 2006, respectively. The accumulated benefit obligation in excess of plan assets is as follows (in thousands):

	December 31,			
	2007		2006	
	Retirement Income Plan	Non-Qualified Retirement Income Plans	Retirement Income Plan	Non-Qualified Retirement Income Plans
Projected benefit obligation	$ (180,301)	$ (20,397)	$ (182,222)	$ (22,112)
Accumulated benefit obligation	(149,308)	(15,352)	(151,569)	(21,101)
Fair value of plan assets	169,028	–	146,425	–

Amounts recognized in accumulated other comprehensive income consist of the following (in thousands):

	Years Ended December 31,			
	2007		2006	
	Retirement Income Plan	Non-Qualified Retirement Income Plans	Retirement Income Plan	Non-Qualified Retirement Income Plans
Net loss	$ 24,603	$ 2,589	$ 44,000	$ 4,379
Prior service cost	110	785	132	879
Total	$ 24,713	$ 3,374	$ 44,132	$ 5,258

The following are the weighted-average actuarial assumptions used to determine the benefit obligations:

	December 31,					
	2007			2006		
		Non-Qualified			Non-Qualified	
	Retirement Income Plan	Retirement Income Plan	Excess Benefit Plan	Retirement Income Plan	Retirement Income Plan	Excess Benefit Plan
Discount rate	6.40%	6.10%	6.40%	5.90%	5.70%	5.90%
Rate of compensation increase	5.00%	N/A	5.00%	5.00%	N/A	5.00%

The components of net periodic benefit cost are presented below (in thousands):

	Years Ended December 31,					
	2007		2006		2005	
	Retirement Income Plan	Non-Qualified Retirement Income Plans	Retirement Income Plan	Non-Qualified Retirement Income Plans	Retirement Income Plan	Non-Qualified Retirement Income Plans
Service cost	$ 5,455	$ 179	$ 5,466	$ 141	$ 5,021	$ 143
Interest cost	10,794	1,263	9,892	1,236	9,351	1,281
Expected return on plan assets	(12,537)	–	(11,029)	–	(9,426)	–
Amortization of:						
Net loss	3,161	257	4,202	299	3,938	291
Prior service cost	21	94	22	94	21	94
Net periodic benefit cost	$ 6,894	$ 1,793	$ 8,553	$ 1,770	$ 8,905	$ 1,809

The changes in benefit obligations recognized in other comprehensive income are presented below (in thousands):

	Years Ended December 31,					
	2007		2006		2005	
	Retirement Income Plan	Non-Qualified Retirement Income Plans	Retirement Income Plan	Non-Qualified Retirement Income Plans	Retirement Income Plan	Non-Qualified Retirement Income Plans
Net gain	$ (16,236)	$ (1,533)				
Amortization of:						
Net loss	(3,161)	(257)				
Prior service cost	(21)	(94)				
Increase (decrease) in minimum liability included in other comprehensive income before adoption of SFAS No. 158	–	–	$ (16,363)	$ (560)	$ 5,757	$ 371
Increase (decrease) in accumulated other comprehensive income due to adoption of SFAS No. 158	–	–	30,785	1,781	–	–
Total expense (income) recognized in other comprehensive income	$ (19,418)	$ (1,884)	$ 14,422	$ 1,221	$ 5,757	$ 371

The total amount recognized in net periodic benefit costs and other comprehensive income are presented below (in thousands):

	Years Ended December 31,					
	2007		2006		2005	
	Retirement Income Plan	Non-Qualified Retirement Income Plans	Retirement Income Plan	Non-Qualified Retirement Income Plans	Retirement Income Plan	Non-Qualified Retirement Income Plans
Total recognized in net periodic benefit cost and other comprehensive income	$ (12,524)	$ (91)	$ 22,975	$ 2,991	$ 14,662	$ 2,180

The following are amounts in accumulated other comprehensive income that are expected to be recognized as components of net periodic benefit cost during 2008 (in thousands):

	Retirement Income Plan	Non-Qualified Retirement Income Plans
Net loss	$ 660	$ 55
Prior service cost	21	94

The following are the weighted-average actuarial assumptions used to determine the net periodic benefit cost at December 31:

	2007			2006			2005		
		Non-Qualified			Non-Qualified			Non-Qualified	
	Retirement Income Plan	Retirement Income Plan	Excess Benefit Plan	Retirement Income Plan	Retirement Income Plan	Excess Benefit Plan	Retirement Income Plan	Retirement Income Plan	Excess Benefit Plan
Discount rate	5.90%	5.70%	5.90%	5.50%	5.50%	5.50%	5.75%	5.75%	5.75%
Expected long-term return on plan assets	8.50%	N/A	N/A	8.50%	N/A	N/A	8.50%	N/A	N/A
Rate of compensation increase	5.00%	N/A	5.00%	5.00%	N/A	5.00%	5.00%	N/A	5.00%

The Company reassesses various actuarial assumptions at least on an annual basis. The discount rate is changed at each measurement date based on prevailing market interest rates inherent in high-quality (AA and better) corporate bonds that would provide the future cash flow needed to pay the benefits included in the benefit obligation as they become due, as well as on publicly available bond indices. The Company changed its discount rate to determine the benefit obligations for the retirement income plan and the excess benefit plan from 5.90% to 6.40% and the non-qualified retirement income

plan from 5.70% to 6.10% at December 31, 2007. For determining 2008 benefit costs, the Company changed its discount rate for the retirement income plan and the excess benefit plan from 5.50% to 5.90% and the non-qualified retirement income plan from 5.50% to 5.70%. A 1.0% decrease in the discount rate would increase the 2007 retirement plans' projected benefit obligation by 14.7%. A 1.0% increase in the discount rate would decrease the 2007 retirement plans' projected benefit obligation by 12.0%.

The Company's overall expected long-term rate of return on assets is 8.50%, which is both a pre-tax and after-tax rate as pension funds are generally not subject to income tax. The expected long-term rate of return is based on the weighted average of the expected returns on investments based upon the target asset allocation of the pension fund. The Retirement Plan fund includes a diversified portfolio of mutual funds investing in equity securities including large and small capital funds, international funds, and an energy industry specific fund. In addition, the Retirement Plan fund includes mutual funds that invest in commodities and emerging market debt. The Retirement Plan fund also invests in fixed income securities. The target long-term asset allocation provides for investments in real estate. The expected returns for mutual fund investments are based on historical risk premiums above the current fixed income rate, while the expected returns for the fixed income securities are based on the portfolio's yield to maturity.

The Company's Retirement Plan fund actual and target long-term asset allocations are as follows:

	December 31,			
	2007		2006	
Asset Category	Actual	Target	Actual	Target
Equity funds	60%	60%	54%	55%
Fixed income	40	35	37	35
Alternative investments	–	5	9	10
Total	100%	100%	100%	100%

The Company adheres to the traditional capital market pricing theory which maintains that over the long term, the risk of owning equities should be rewarded with a greater return than available from fixed income investments. The Company seeks to minimize the risk of owning equity securities by investing in mutual funds that pursue risk minimization strategies and by diversifying its investments to limit its risks during falling markets. The investment managers have full discretionary authority to direct the investment of plan assets held in trust within the guidelines prescribed by the Company through the plan's investment policy statement including the ability to hold cash equivalents. The investment guidelines of the investment policy statement are in accordance with the Employee Retirement Income Security Act of 1974 (ERISA) and Department of Labor (DOL) regulations.

The contributions for the Retirement Plan, as actuarially calculated, are at least the minimum funding amounts required by the IRS. The Company expects to contribute $13.6 million to its retirement plans in 2008, although the Company has no 2008 minimum funding requirements for the Retirement Plan.

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid (in thousands):

	Retirement Income Plan	Non-Qualified Retirement Income Plans
2008	$ 6,247	$ 1,582
2009	6,829	1,563
2010	7,465	1,623
2011	8,178	1,596
2012	9,002	1,574
2013-2017	60,383	9,145

Other Postretirement Benefits

The Company provides certain health care benefits for retired employees and their eligible dependents and life insurance benefits for retired employees only. Substantially all of the Company's employees may become eligible for those benefits if they retire while working for the Company. Contributions from the Company are based on the funding amounts established in Texas Commission Docket No. 12700. The assets of the plan are invested in equity securities, debt securities, and cash equivalents and are managed by professional investment managers appointed by the Company.

The Company determined that the prescription drug benefits of its plan were actuarially equivalent to the Medicare Part D benefit provided for in the Medicare Prescription Drug, Improvement, and Modernization Act of 2003. FASB Staff Position No. 106-2 "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003" requires measurement of the postretirement benefit obligation, the plan assets, and the net periodic postretirement benefit cost to reflect the effects of the subsidy.

The following table contains a reconciliation of the change in the benefit obligation, the fair value of plan assets, and the funded status of the plans (in thousands):

	December 31,	
	2007	2006
Change in benefit obligation:		
Benefit obligation at end of prior year	$ 113,933	$ 112,769
Service cost	3,870	4,584
Interest cost	6,053	5,762
Actuarial gain	(22,801)	(6,863)
Benefits paid	(2,810)	(2,658)
Retiree contributions	367	339
Benefit obligation at end of year	98,612	113,933
Change in plan assets:		
Fair value of plan assets at end of prior year	28,498	24,717
Actual return on plan assets	1,750	2,678
Employer contribution	3,422	3,422
Benefits paid	(2,810)	(2,658)
Retiree contributions	367	339
Fair value of plan assets at end of year	31,227	28,498
Funded status	$ (67,385)	$ (85,435)

Amounts recognized in the Company's consolidated balance sheets as a non-current liability consist of accrued postretirement costs of $67.4 million and $85.4 million for 2007 and 2006, respectively.

On December 31, 2006, the Company adopted SFAS No. 158 "Employer's Accounting for Defined Benefit Pension and Other Postretirement Plans", which amended SFAS No. 106 and SFAS No. 132R. The Company uses a measurement date of December 31 for its other postretirement benefits plan, therefore there were no adjustments related to a change in measurement date as a result of the adoption of SFAS No. 158.

Amounts recognized in accumulated other comprehensive income that have not been recognized as a component of net periodic cost in accordance with SFAS No. 158 consist of the following (in thousands):

	Years Ended December 31,	
	2007	2006
Net gain	$ (23,604)	$ (780)
Prior service credit	(18,577)	(21,446)
	$ (42,181)	$ (22,226)

The following are the weighted-average actuarial assumptions used to determine the accrued postretirement costs:

	2007	2006
Discount rate at end of year	6.50%	5.90%
Trend rates:		
Initial	9.50%	9.60%
Ultimate	5.00%	6.00%
Years ultimate reached	10	4

Net periodic benefit cost is made up of the components listed below (in thousands):

	Years Ended December 31,		
	2007	2006	2005
Service cost	$ 3,870	$ 4,584	$ 4,749
Interest cost	6,053	5,762	6,667
Expected return on plan assets	(1,695)	(1,478)	(1,382)
Amortization of:			
Prior service benefit	(2,869)	(2,869)	(355)
Net gain	(32)	–	–
Net periodic benefit cost	$ 5,327	$ 5,999	$ 9,679

The changes in benefit obligations recognized in accumulated other comprehensive income are presented below (in thousands):

	Years Ended December 31,	
	2007	2006
Net gain	$ (22,856)	
Amortization of:		
Prior service benefit	2,869	
Net gain	32	
Increase (decrease) in accumulated other comprehensive income due to adoption of SFAS No. 158	–	$ (22,226)
Total recognized in other comprehensive income	$ (19,955)	$ (22,226)

The total recognized in net periodic benefit cost and other comprehensive income are presented below (in thousands):

	Years Ended December 31,		
	2007	2006	2005
Total recognized in net periodic benefit cost and other comprehensive income	$ (14,628)	$ (16,227)	$ 9,679

The following are amounts in accumulated other comprehensive income that are expected to be recognized as components of net periodic benefit cost during 2008 (in thousands):

Prior service benefit	$ (2,869)
Net gain	(1,127)

The following are the weighted-average actuarial assumptions used to determine the net periodic benefit cost:

	2007	2006	2005
Discount rate at beginning of year	5.90%	5.50%	5.75%
Expected long-term return on plan assets	5.90%	5.90%	5.90%
Trend rates:			
Initial	9.60%	9.60%	9.60%
Ultimate	6.00%	6.00%	6.00%
Years ultimate reached	4	4	4

The Company reassesses various actuarial assumptions at least on an annual basis. The discount rate is evaluated at each measurement date based on prevailing market interest rates inherent in high-quality (AA and better) corporate bonds that would provide the future cash flow needed to pay the benefits included in the benefit obligation as they become due, as well as on publicly available bond indices. At December 31, 2007, the Company changed its discount rate from 5.90% to 6.50% for the other postretirement benefits plan. For determining 2008 benefit cost, the Company changed its discount rate from 5.50% to 5.90%. A 1.0% decrease in the discount rate would increase the 2007 accumulated postretirement benefit obligation by 16.7%. A 1.0% increase in the discount rate would decrease the 2007 accumulated postretirement benefit obligation by 17.5%.

For measurement purposes, a 9.5% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2008; the rate was assumed to decrease gradually to 5% for 2017 and remain at that level thereafter. Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plan. The effect of a 1% change in these assumed health care cost

trend rates would increase or decrease the benefit obligation by $15.5 million or $12.6 million, respectively. In addition, such a 1% change would increase or decrease the aggregate service and interest cost components of the net periodic benefit cost by $1.9 million or $1.5 million, respectively.

The Company's overall expected long-term rate of return on assets, on an after-tax basis, is 5.90%. The expected long-term rate of return is based on the after-tax weighted average of the expected returns on investments based upon the target asset allocation. The asset portfolio includes a diversified mix of mutual funds investing in equity securities including large and small capital funds, international funds, and an energy industry specific fund. In addition, the asset portfolio includes mutual funds that invest in commodities and emerging market debt. The asset portfolio also includes fixed income securities and cash equivalents. The target long-term asset allocation provides for investments in real estate. The expected returns for mutual fund investments are based on historical risk premiums above the current fixed income rate, while the expected returns for the fixed income securities are based on the portfolio's yield to maturity. The Company's asset portfolio actual and target long-term asset allocations are as follows:

	December 31,			
	2007		2006	
Asset Category	Actual	Target	Actual	Target
Equity funds	70%	65%	62%	60%
Fixed income	30	30	29	30
Alternative investments	–	5	9	10
Total	100%	100%	100%	100%

The Company adheres to the traditional capital market pricing theory which maintains that over the long term, the risk of owning equities should be rewarded with a greater return than available from fixed income investments. The Company seeks to minimize the risk of owning equity securities by investing in mutual funds that pursue risk minimization strategies and by diversifying its investments to limit its risks during falling markets. The investment managers have full discretionary authority to direct the investment of plan assets held in trust within the guidelines prescribed by the Company through the plan's investment policy statement including the ability to hold cash equivalents. The investment guidelines of the investment policy statement are in accordance with the ERISA and DOL regulations.

The Company expects to contribute $3.4 million to its other postretirement benefits plan in 2008.

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid (in thousands):

	Including Medicare Part D Subsidy	Excluding Medicare Part D Subsidy	Reduction due to the Medicare Part D Subsidy
2008	$ 2,946	$ 3,220	$ (274)
2009	3,355	3,666	(311)
2010	3,877	4,223	(346)
2011	4,434	4,825	(391)
2012	5,030	5,468	(438)
2013-2017	34,602	37,815	(3,213)

401(k) Defined Contribution Plans

The Company sponsors 401(k) defined contribution plans covering substantially all employees. Historically, the Company has provided a 50 percent matching contribution up to 6 percent of the employee's compensation subject to certain other limits and exclusions. Total matching contributions made to the savings plans for the years 2007, 2006 and 2005 were $1.6 million, $1.5 million and $1.5 million, respectively.

Annual Short-Term Bonus Plan

The Annual Short-Term Bonus Plan (the "Bonus Plan") provides for the payment of cash awards to eligible Company employees, including each of its named executive officers. Payment of awards is based on the achievement of performance measures reviewed and approved by the Company's Board of Directors Compensation Committee. Generally, these performance measures are based on meeting certain financial, operational and individual performance criteria. The financial performance goals are based on earnings per share and the operational performance goals are based on safety and customer satisfaction. If a certain level of earnings per share is not attained, no bonuses will be paid under the Bonus Plan. The Company reached the required levels of improvements in the earnings per share, customer satisfaction, safety goals to pay a bonus of $7.0 million, $6.1 million and $3.5 million for 2007, 2006 and 2005, respectively. The Company has renewed the Bonus Plan in 2008 with similar goals.

L. Franchises and Significant Customers

El Paso Franchise

The Company has a franchise agreement with El Paso, the largest city it serves, through July 31, 2030. The franchise agreement includes a franchise fee of 3.25% of revenues and allows the Company to utilize public rights-of-way necessary to serve its retail customers within El Paso.

Las Cruces Franchise

In February 2000, the Company and Las Cruces entered into a seven-year franchise agreement with a franchise fee of 2% of revenues (approximately $1.5 million per year) for the provision of electric distribution service. Las Cruces exercised its right to extend the franchise for an additional two-year term ending April 30, 2009 and waived its option to purchase the Company's distribution system pursuant to the terms of the February 2000 settlement agreement.

Military Installations

The Company currently serves Holloman Air Force Base ("Holloman"), White Sands Missile Range ("White Sands") and the United States Army Air Defense Center at Fort Bliss ("Ft. Bliss"). The Company's sales to the military bases represent approximately 2% of annual operating revenues. The Company signed a contract with Ft. Bliss in December 1998 under which Ft. Bliss will take retail electric service from the Company through December 2008. In May 1999, the Army and the Company entered into a ten-year contract to provide retail electric service to White Sands. In March 2006, the Company signed a contract with Holloman that provides for the Company to provide retail electric service and limited wheeling services to Holloman for a ten-year term which expires in January 2016.

M. Financial Instruments and Investments

SFAS No. 107, "Disclosure about Fair Value of Financial Instruments," requires the Company to disclose estimated fair values for its financial instruments. The Company has determined that cash and temporary investments, investment in debt securities, accounts receivable, decommissioning trust funds, long-term debt and financing obligations, accounts payable and customer deposits meet the definition of financial instruments. The carrying amounts of cash and temporary investments, accounts receivable, accounts payable and customer deposits approximate fair value because of the short maturity of these items. Decommissioning trust funds are carried at market value.

The fair values of the Company's long-term debt and financing obligations, including the current portion thereof, are based on estimated market prices for similar issues and are presented below (in thousands):

	December 31,			
	2007		2006	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Pollution Control Bonds	$ 193,135	$ 192,820	$ 193,135	$ 193,539
Senior Notes	397,759	376,150	397,730	384,920
Nuclear Fuel Financing (1)	83,015	83,015	46,240	46,240
Total	$ 673,909	$ 651,985	$ 637,105	$ 624,699

(1) The interest rate on the Company's financing for nuclear fuel purchases is reset every quarter to reflect current market rates. Consequently, the carrying value approximates fair value.

Treasury Rate Locks. During the first quarter of 2005, the Company entered into treasury rate lock agreements to hedge against potential movements in the treasury reference interest rate pending the issuance of the Notes. These treasury rate locks were terminated on May 11, 2005. The treasury rate lock agreements met the criteria for hedge accounting and were designated as a cash flow hedge. In accordance with cash flow hedge accounting, the Company recorded the loss associated with the fair value of the cash flow hedge of approximately $14.0 million, net of tax, as a component of accumulated other comprehensive loss. In May 2005, the Company began to recognize in earnings (as additional interest expense) the accumulated other comprehensive loss associated with the cash flow hedge. During the next twelve month period, approximately $0.3 million of this accumulated other comprehensive loss item will be reclassified to interest expense.

Contracts and Derivative Accounting. The Company uses commodity contracts to manage its exposure to price and availability risks for fuel purchases and power sales and purchases and these contracts generally have the characteristics of derivatives. The Company does not trade or use these instruments with the objective of earning financial gains on the commodity price fluctuations. The Company has determined that all such contracts outstanding at December 31, 2007, except for certain natural gas commodity contracts with optionality features, that had the characteristics of derivatives met the "normal purchases and normal sales" exception provided in SFAS No. 133, and, as such, were not required to be accounted for as derivatives pursuant to SFAS No. 133 and other guidance.

The Company determined that certain of its natural gas commodity contracts with optionality features are not eligible for the normal purchases exception and, therefore, are required to be accounted for as derivative instruments pursuant to SFAS No. 133. However, as of December 31, 2007, the variable, market-based pricing provisions of existing gas contracts are such that these derivative instruments have no significant fair value.

Marketable Securities. The Company's marketable securities, included in decommissioning trust funds in the balance sheets, are reported at fair value which was $130.7 million and $114.7 million at December 31, 2007 and 2006, respectively. Gross unrealized losses on marketable securities and the fair value of the related securities, aggregated by investment category and length of time that individual securities have been in a continuous unrealized loss position, at December 31, 2007 and 2006, were as follows (in thousands):

	December 31, 2007					
	Less than 12 Months		12 Months or Longer		Total	
	Fair Value	Unrealized Losses	Fair Value	Unrealized Losses	Fair Value	Unrealized Losses
Description of Securities:						
Federal Agency Mortgage Backed Securities	$ 944	$ (2)	$ 2,253	$ (34)	$ 3,197	$ (36)
Municipal Obligations	3,072	(11)	6,995	(54)	10,067	(65)
Corporate Obligations	1,119	(24)	880	(10)	1,999	(34)
Total debt securities	5,135	(37)	10,128	(98)	15,263	(135)
Common stock	9,031	(1,464)	–	–	9,031	(1,464)
Total temporarily impaired securities	$ 14,166	$ (1,501)	$ 10,128	$ (98)	$ 24,294	$ (1,599)

	December 31, 2006					
	Less than 12 Months		12 Months or Longer		Total	
	Fair Value	Unrealized Losses	Fair Value	Unrealized Losses	Fair Value	Unrealized Losses
Description of Securities:						
U.S. Treasury Obligations and Direct Obligations of U.S. Government Agencies	$ 4,223	$ (21)	$ 5,532	$ (184)	$ 9,755	$ (205)
Federal Agency Mortgage Backed Securities	250	(2)	590	(30)	840	(32)
Municipal Obligations	12,336	(56)	1,517	(65)	13,853	(121)
Corporate Obligations	612	(7)	841	(27)	1,453	(34)
Total debt securities	17,421	(86)	8,480	(306)	25,901	(392)
Common stock	4,510	(161)	662	(199)	5,172	(360)
Total temporarily impaired securities	$ 21,931	$ (247)	$ 9,142	$ (505)	$ 31,073	$ (752)

The total impaired securities are comprised of approximately 80 investments that are in an unrealized loss position. The Company monitors the length of time the investment trades below its cost basis along with the amount and percentage of the unrealized loss in determining if a decline in fair value of marketable securities below original cost is considered to be other than temporary. In addition, the Company will research the future prospects of individual securities as necessary. As a result of these factors, as well as the Company's intent and ability to hold these investments until their market price recovers, these investments are not considered other-than-temporarily impaired. The Company will not have a requirement to expend monies held in trust before 2024 or a later period when the Company begins to decommission Palo Verde. For 2007, the Company realized a $0.8 million gain on the sale of investments that were previously considered impaired. During the year ended December 31, 2006, the Company recognized other than temporary impairment losses of marketable securities of $0.5 million. The Company did not recognize any impairment losses for 2007 or 2005.

N. Supplemental Statements of Cash Flows Disclosures

	Years Ended December 31,		
	2007	2006	2005
		(In thousands)	
Cash paid for:			
Interest on long-term debt and financing obligations	$ 34,146	$ 33,302	$ 48,407
Income taxes	26,312	5,666	1,195
Non-cash financing activities:			
Grants of restricted shares of common stock	3,502	1,529	1,975
Deferred tax benefit on long-term incentive plans	3,993	954	–

O. Selected Quarterly Financial Data (Unaudited)

	2007 Quarters				2006 Quarters			
	4th	3rd	2nd	1st	4th	3rd	2nd	1st
	(In thousands except for share data)							
Operating revenues (1)	$ 211,194	$ 258,525	$219,291	$188,417	$193,281	$228,949	$211,796	$182,429
Operating income	15,971	60,990	21,451	29,909	19,968	51,055	22,192	22,347
Income before extraordinary item (2)	13,947	36,088	9,599	15,119	9,758	27,076	15,249	9,304
Extraordinary gain on re-application of SFAS No. 71, net of tax	–	–	–	–	6,063	–	–	–
Net income	13,947	36,088	9,599	15,119	15,821	27,076	15,249	9,304
Basic earnings per share:								
Income before extraordinary item	0.31	0.79	0.21	0.33	0.21	0.57	0.32	0.19
Extraordinary gain on re-application of SFAS No. 71, net of tax	–	–	–	–	0.13	–	–	–
Net income	0.31	0.79	0.21	0.33	0.34	0.57	0.32	0.19
Diluted earnings per share:								
Income before extraordinary item	0.30	0.79	0.21	0.33	0.21	0.56	0.31	0.19
Extraordinary gain on re-application of SFAS No. 71, net of tax	–	–	–	–	0.13	–	–	–
Net income	0.30	0.79	0.21	0.33	0.34	0.56	0.31	0.19

(1) Operating revenues are seasonal in nature, with the peak sales periods generally occurring during the summer months. Comparisons among quarters of a year may not represent overall trends and changes in operations.

(2) During the fourth quarter of 2007, net income was positively affected by $4.0 million of deferred income tax adjustments related to earlier quarters and the reversal of a $1.7 million reserve for rate refund upon completion of contract negotiations with a large Texas customer.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Evaluation of disclosure controls and procedures. During the period covered by this report, our chief executive officer and chief financial officer, after evaluating the effectiveness of the Company's "disclosure controls and procedures" (as defined in the Securities Exchange Act of 1934 Rules 13a-15(e) and 15d-15(e)) as of December 31, 2007, (the "Evaluation Date"), concluded that as of the Evaluation Date, our disclosure controls and procedures (as required by paragraph (b) of the Securities Exchange Act of 1934 Rules 13a-15 or 15d-15) were adequate and designed to ensure that material information relating to us and our consolidated subsidiary would be made known to them by others within those entities.

Management's Annual Report on Internal Control Over Financial Reporting. Included herein under the caption "Management Report on Internal Control Over Financial Reporting" on page 56 of this report.

Changes in internal control over financial reporting. There were no changes in our internal control over financial reporting in connection with the evaluation required by paragraph (d) of the Securities Exchange Act of 1934 Rules 13a-15 or 15d-15, that occurred during the quarter ended December 31, 2007, that materially affected, or that were reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

None.

PART III

Item 10. Directors and Executive Officers of the Registrant

Information regarding directors is incorporated herein by reference from our definitive proxy statement for the 2008 Annual Meeting of Shareholders (the "2008 Proxy Statement") under the heading "Nominee and Directors of the Company." Information regarding executive officers, included herein under the caption "Executive Officers of the Registrant" in Part I, Item 1 above, is incorporated herein by reference.

The information concerning the identification of our standing audit committee required by this Item is incorporated by reference from the 2008 Proxy Statement under the caption "Committees" under the heading "Directors' Meetings, Compensation and Committees," and under the heading "Audit Committee Report."

The information concerning our audit committee financial experts required by this Item is incorporated by reference from the 2008 Proxy Statement under the caption "Committees" under the heading "Directors' Meetings, Compensation and Committees."

The information concerning compliance with Section 16(a) of the Exchange Act required by this Item is incorporated by reference from the 2008 Proxy Statement under the heading "Section 16(a) Beneficial Ownership Reporting Compliance."

We have adopted a Code of Ethics that is incorporated by reference from the 2008 Proxy Statement under the caption "Business Conduct Policies" under the heading "Corporate Governance."

Item 11. Executive Compensation

Incorporated herein by reference from the 2008 Proxy Statement under the heading "Summary of Compensation."

Item 12. Security Ownership of Certain Beneficial Owners and Management

Incorporated herein by reference from the 2008 Proxy Statement under the heading "Security Ownership of Certain Beneficial Owners and Management."

Equity Compensation Plan Information

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders	573,888	$ 13.26	1,113,486
Equity compensation plans not approved by security holders	–	–	–
Total	573,888	$ 13.26	1,113,486

Item 13. Certain Relationships and Related Transactions

Incorporated herein by reference from the 2008 Proxy Statement under the heading "Certain Relationships and Related Party Transactions."

Item 14. Principal Accounting Fees and Services

Incorporated herein by reference from the 2008 Proxy Statement under the heading "Independent Registered Public Accounting Firm."

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) Documents filed as a part of this report:

Page

1. Financial Statements:

   See Index to Financial Statements 57

2. Financial Statement Schedules:

   All schedules are omitted as the required information is not applicable or is included in the financial statements or related notes thereto.

3. Exhibits

Certain of the following documents are filed herewith. Certain other of the following exhibits have heretofore been filed with the Securities and Exchange Commission, and, pursuant to Rule 12b-32 and Regulation 201.24, are incorporated herein by reference.

INDEX TO EXHIBITS

Exhibit Number	Title
Exhibit 3 – Articles of Incorporation and Bylaws:	
3.01	– Restated Articles of Incorporation of the Company, dated February 7, 1996 and effective February 12, 1996. (Exhibit 3.01 to the Company's Annual Report on Form 10-K for the year ended December 31, 1995)
3.02	– Bylaws of the Company, dated February 6, 1996. (Exhibit 3.02 to the Company's Annual Report on Form 10-K for the year ended December 31, 1995)
Exhibit 4 – Instruments Defining the Rights of Security Holders, including Indentures:	
4.01	– General Mortgage Indenture and Deed of Trust, dated as of February 1, 1996, and First Supplemental Indenture, dated as of February 1, 1996, including form of Series A through H First Mortgage Bonds. (Exhibit 4.01 to the Company's Annual Report on Form 10-K for the year ended December 31, 1995)
4.01-01	– Second Supplemental Indenture, dated as of August 19, 1997, to Exhibit 4.01. (Exhibit 4.01 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 1997)
4.01-02	– Fifth Supplemental Indenture, dated as of December 17, 2004, to Exhibit 4.01. (Exhibit 4.01-02 to the Company's Annual Report on Form 10-K for the year ended December 31, 2004)
4.01-03	– Sixth Supplemental Indenture to Exhibit 4.01, dated as of May 5, 2005 to General Mortgage Indenture and Deed of Trust dated as of February 1, 1996 between the Company and U.S. Bank National Association as trustee. (Exhibit 4.01 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2005)
4.02	– Reserved
4.03	– Indenture of Trust between Maricopa County, Arizona Pollution Control Corporation and Union Bank of California, N.A. as Trustee dated as of July 1, 2005 relating to $59,235,000 Maricopa County, Arizona Pollution Control Corporation Pollution Control Refunding Revenue Bonds 2005 Series A (El Paso Electric Company Palo Verde Project). (Exhibit 4.30 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2005)
4.04	– Loan Agreement dated July 1, 2005 between Maricopa County, Arizona Pollution Control Corporation and El Paso Electric Company relating to the Pollution Control Bonds referred to in Exhibit 4.03. (Exhibit 4.31 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2005)

INDEX TO EXHIBITS

Exhibit Number	Title
4.05	– Representation and Indemnity Agreement dated July 27, 2005 among El Paso Electric Company, Citigroup Global Markets Inc., BNY Capital Markets, Inc., J.P. Morgan Securities Inc., and the Maricopa County, Arizona Pollution Control Corporation, relating to the Pollution Control Bonds referred to in Exhibit 4.03. (Exhibit 4.32 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2005)
4.06	– Indenture of Trust between Maricopa County, Arizona Pollution Control Corporation and Union Bank of California, N.A. as Trustee dated as of July 1, 2005 relating to $63,500,000 Maricopa County, Arizona Pollution Control Corporation Pollution Control Refunding Revenue Bonds 2005 Series B (El Paso Electric Company Palo Verde Project). (Exhibit 4.33 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2005)
4.07	– Loan Agreement dated July 1, 2005 between Maricopa County, Arizona Pollution Control Corporation and El Paso Electric Company relating to the Pollution Control Bonds referred to in Exhibit 4.06. (Exhibit 4.34 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2005)
4.08	– Indenture of Trust between Maricopa County, Arizona Pollution Control Corporation and Union Bank of California, N.A. as Trustee dated as of July 1, 2005 relating to $37,100,000 Maricopa County, Arizona Pollution Control Corporation Pollution Control Refunding Revenue Bonds 2005 Series C (El Paso Electric Company Palo Verde Project). (Exhibit 4.35 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2005)
4.09	– Loan Agreement dated July 1, 2005 between Maricopa County, Arizona Pollution Control Corporation and El Paso Electric Company relating to the Pollution Control Bonds referred to in Exhibit 4.08. (Exhibit 4.36 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2005)
4.10	– Remarketing Agreement dated August 1, 2005 between El Paso Electric Company and Citigroup Global Markets Inc. relating to the Pollution Control Bonds referred to in Exhibits 4.03, 4.06 and 4.08. (Exhibit 4.37 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2005)
4.11	– Tender Agreement dated August 1, 2005 between El Paso Electric Company and Citigroup Global Markets Inc. relating to the Pollution Control Bonds referred to in Exhibits 4.03, 4.06 and 4.08. (Exhibit 4.38 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2005)

INDEX TO EXHIBITS

Exhibit Number	Title
4.12	– Broker-Dealer Agreement dated August 1, 2005 among The Bank of New York, as Auction Agent, Citigroup Global Markets Inc., as Broker-Dealer and El Paso Electric Company, as Borrower, relating to the Pollution Control Bonds referred to in Exhibits 4.06 and 4.08. (Exhibit 4.39 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2005)
4.13	– Auction Agent Agreement dated as of August 1, 2005 among El Paso Electric Company and Union Bank of California, N.A., as Trustee and The Bank of New York, as Auction Agent, relating to the Pollution Control Bonds referred to in Exhibits 4.06 and 4.08. (Exhibit 4.40 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2005)
4.14	– Representation and Indemnity Agreement dated July 27, 2005 among El Paso Electric Company, Citigroup Global Markets Inc., BNY Capital Markets, Inc., J.P. Morgan Securities Inc., and the Maricopa County, Arizona Pollution Control Corporation, relating to the Pollution Control Bonds referred to in Exhibits 4.06 and 4.08. (Exhibit 4.41 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2005)
4.15	– Remarketing and Purchase Agreement dated July 27, 2005 among El Paso Electric Company and Citigroup Global Markets Inc., as remarketing agent, and Citigroup Global Markets Inc., BNY Capital Markets, Inc., and J.P. Morgan Securities Inc. relating to the Pollution Control Bonds referred to in Exhibit 4.22 to the Company's Annual Report on Form 10-K for the year ended December 31, 2004. (Exhibit 4.42 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2005)
4.16	– Tender Agreement dated August 1, 2005 between El Paso Electric Company and Citigroup Global Markets Inc. relating to the Pollution Control Bonds referred to in Exhibit 4.22 to the Company's Annual Report on Form 10-K for the year ended December 31, 2004. (Exhibit 4.43 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2005)
4.17	– Remarketing Agreement dated August 1, 2005 between El Paso Electric Company and Citigroup Global Markets Inc. relating to the Pollution Control Bonds referred to in Exhibit 4.22 to the Company's Annual Report on Form 10-K for the year ended December 31, 2004. (Exhibit 4.44 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2005)

INDEX TO EXHIBITS

Exhibit Number	Title
4.18	– Ordinance No. 2002-1134 adopted by the City Council of Farmington, New Mexico on July 9, 2002 authorizing and providing for the issuance by the City of Farmington, New Mexico of $33,300,000 principal amount of its Pollution Control Revenue Refunding Bonds, 2002 Series A (El Paso Electric Company Four Corners Project). (Exhibit 4.22 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2002)

Exhibit 10 – Material Contracts:

10.01	– Co-Tenancy Agreement, dated July 19, 1966, and Amendments No. 1 through 5 thereto, between the Participants of the Four Corners Project, defining the respective ownerships, rights and obligations of the Parties. (Exhibit 10.01 to the Company's Annual Report on Form 10-K for the year ended December 31, 1995)
10.01-01	– Amendment No. 6, dated February 3, 2000, to Exhibit 10.01. (Exhibit 10.01-01 to the Company's Annual Report on Form 10-K for the year ended December 31, 2002)
10.02	– Supplemental and Additional Indenture of Lease, dated May 27, 1966, including amendments and supplements to original Lease Four Corners Units 1, 2 and 3, between the Navajo Tribe of Indians and Arizona Public Service Company, and including new Lease Four Corners Units 4 and 5, between the Navajo Tribe of Indians and Arizona Public Service Company, the Company, Public Service Company of New Mexico, Salt River Project Agricultural Improvement and Power District, Southern California Edison Company and Tucson Gas & Electric Company. (Exhibit 4-e to Registration Statement No. 2-28692 on Form S-9)
10.02-01	– Amendment and Supplement No. 1, dated March 21, 1985, to Exhibit 10.02. (Exhibit 19.3 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 1985)
10.03	– El Paso Electric Company 1996 Long-Term Incentive Plan. (Exhibit 4.1 to Registration Statement No. 333-17971 on Form S-8)
10.04	– Four Corners Project Operating Agreement, dated May 15, 1969, between Arizona Public Service Company, the Company, Public Service Company of New Mexico, Salt River Project Agricultural Improvement and Power District, Southern California Edison Company and Tucson Gas & Electric Company, and Amendments 1 through 10 thereto. (Exhibit 10.04 to the Company's Annual Report on Form 10-K for the year ended December 31, 1995)
10.04-01	– Amendment No. 11, dated May 23, 1997, to Exhibit 10.04. (Exhibit 10.04-01 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 1997)

INDEX TO EXHIBITS

Exhibit Number	Title
10.04-02	– Amendment No. 12, dated February 3, 2000, to Exhibit 10.04. (Exhibit 10.04-02 to the Company's Annual Report on Form 10-K for the year ended December 31, 2002)
10.05	– Arizona Nuclear Power Project Participation Agreement, dated August 23, 1973, between Arizona Public Service Company, Public Service Company of New Mexico, Salt River Project Agricultural Improvement and Power District, Tucson Gas & Electric Company and the Company, describing the respective participation ownerships of the various utilities having undivided interests in the Arizona Nuclear Power Project and in general terms defining the respective ownerships, rights, obligations, major construction and operating arrangements of the Parties, and Amendments No. 1 through 13 thereto. (Exhibit 10.05 to the Company's Annual Report on Form 10-K for the year ended December 31, 1995)
10.05-01	– Amendment No. 14, dated June 20, 2000, to Exhibit 10.05. (Exhibit 10.05-01 to the Company's Annual Report on Form 10-K for the year ended December 31, 2002)
10.06	– ANPP Valley Transmission System Participation Agreement, dated August 20, 1981, and Amendments No. 1 and 2 thereto. APS Contract No. 2253-419.00. (Exhibit 10.06 to the Company's Annual Report on Form 10-K for the year ended December 31, 1995)
10.07	– Arizona Nuclear Power Project High Voltage Switchyard Participation Agreement, dated August 20, 1981. APS Contract No. 2252-419.00. (Exhibit 20.14 to the Company's Annual Report on Form 10-K for the year ended December 31, 1981)
10.07-01	– Amendment No. 1, dated November 20, 1986, to Exhibit 10.07. (Exhibit 10.11-01 to the Company's Annual Report on Form 10-K for the year ended December 31, 1986)
10.08	– Firm Palo Verde Nuclear Generating Station Transmission Service Agreement, between Salt River Project Agricultural Improvement and Power District and the Company, dated October 18, 1983. (Exhibit 19.12 to the Company's Annual Report on Form 10-K for the year ended December 31, 1983)
10.09	– Interconnection Agreement, as amended, dated December 8, 1981, between the Company and Southwestern Public Service Company, and Service Schedules A through F thereto. (Exhibit 10.13 to the Company's Annual Report on Form 10-K for the year ended December 31, 1995)

INDEX TO EXHIBITS

Exhibit Number	Title
10.10	– Amrad to Artesia 345 KV Transmission System and DC Terminal Participation Agreement, dated December 8, 1981, between the Company and Texas-New Mexico Power Company, and the First through Third Supplemental Agreements thereto. (Exhibit 10.14 to the Company's Annual Report on Form 10-K for the year ended December 31, 1995)
10.11	– Reserved
10.12	– Interconnection Agreement and Amendment No. 1, dated July 19, 1966, between the Company and Public Service Company of New Mexico. (Exhibit 19.01 to the Company's Annual Report on Form 10-K for the year ended December 31, 1982)
10.13	– Southwest New Mexico Transmission Project Participation Agreement, dated April 11, 1977, between Public Service Company of New Mexico, Community Public Service Company and the Company, and Amendments 1 through 5 thereto. (Exhibit 10.16 to the Company's Annual Report on Form 10-K for the year ended December 31, 1995)
10.13-01	– Amendment No. 6, dated as of June 17, 1999, to Exhibit 10.16. (Exhibit 10.09 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 1999)
10.14	– Tucson-El Paso Power Exchange and Transmission Agreement, dated April 19, 1982, between Tucson Electric Power Company and the Company. (Exhibit 19.26 to the Company's Annual Report on Form 10-K for the year ended December 31, 1982)
10.15	– Southwest Reserve Sharing Group Participation Agreement, dated January 1, 1998, between the Company, Arizona Electric Power Cooperative, Arizona Public Service Company, City of Farmington, Los Alamos County, Nevada Power Company, Plains Electric G&T Cooperative, Inc., Public Service Company of New Mexico, Tucson Electric Power and Western Area Power Administration. (Exhibit 10.18 to the Company's Annual Report on Form 10-K for the year ended December 31, 1997)
10.16	– Arizona Nuclear Power Project Transmission Project Westwing Switchyard Amended Interconnection Agreement, dated August 14, 1986, between The United States of America; Arizona Public Service Company; Department of Water and Power of the City of Los Angeles; Nevada Power Company; Public Service Company of New Mexico; Salt River Project Agricultural Improvement and Power District; Tucson Electric Power Company; and the Company. (Exhibit 10.72 to the Company's Annual Report on Form 10-K for the year ended December 31, 1986)

INDEX TO EXHIBITS

Exhibit Number	Title
10.17	– Form of Indemnity Agreement, between the Company and its directors and officers. (Exhibit 10.22 to the Company's Annual Report on Form 10-K for the year ended December 31, 1995)
10.18	– Interchange Agreement, executed April 14, 1982, between Comision Federal de Electricidad and the Company. (Exhibit 19.2 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 1991)
10.19	– Trust Agreement, dated as of February 12, 1996, between the Company and Texas Commerce Bank National Association, as Trustee of the Rio Grande Resources Trust II. (Exhibit 10.34 to the Company's Annual Report on Form 10-K for the year ended December 31, 1995)
10.20	– Purchase Contract, dated as of February 12, 1996, between the Company and Texas Commerce Bank National Association, as Trustee of the Rio Grande Resources Trust II. (Exhibit 10.35 to the Company's Annual Report on Form 10-K for the year ended December 31, 1995)
10.20-01	– Second Amendment, dated as of July 12, 2007, to the Purchase Contract referred to in Exhibit 10.20 to the Company's Annual Report on Form 10-K for the year ended December 31, 2006. (Exhibit 10.09 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2007)
10.21	– Reserved
10.22	– Decommissioning Trust Agreement, dated as of April 1, 2006, between the Company and Wells Fargo Bank, N.A., as decommissioning trustee for Palo Verde Unit 1. (Exhibit 10.02 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2006)
10.23	– Decommissioning Trust Agreement, dated as of April 1, 2006, between the Company and Wells Fargo Bank, N.A., as decommissioning trustee for Palo Verde Unit 2. (Exhibit 10.03 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2006)
10.24	– Decommissioning Trust Agreement, dated as of April 1, 2006, between the Company and Wells Fargo Bank, N.A., as decommissioning trustee for Palo Verde Unit 3. (Exhibit 10.04 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2006)
10.25	– Employment Agreement for Helen Knopp, dated April 30, 1999. (Exhibit 10.46 to the Company's Annual Report on Form 10-K for the year ended December 31, 1999)
†10.26	– Amended and Restated Change in Control Agreement between the Company and certain key officers of the Company. (Exhibit 9.1 to the Company's Form 8-K as of March 20, 2007)
10.27	– Reserved

INDEX TO EXHIBITS

Exhibit Number	Title
††10.28	– Form of Stock Option Agreement between the Company and certain key officers of the Company. (Exhibit 99.01 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 1998)
†††10.29	– Form of Directors' Restricted Stock Award Agreement between the Company and certain directors of the Company. (Exhibit 10.07 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 1999)
††††10.30	– Form of Directors' Stock Option Agreement between the Company and certain directors of the Company. (Exhibit 99.17 to the Company's Annual Report on Form 10-K for the year ended December 31, 1997)
10.31	– El Paso Electric Company 1999 Long-Term Incentive Plan. (Exhibit 4.1 to Registration Statement No. 333-82129 on Form S-8)
10.32	– Settlement Agreement, dated as of February 24, 2000, with the City of Las Cruces. (Exhibit 10.01 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2000)
10.33	– Franchise Agreement, dated April 3, 2000, between the Company and the City of Las Cruces. (Exhibit 10.02 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2000)
10.34	– Employment Agreement for Hector Puente, dated April 23, 2001. (Exhibit 10.07 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2001)
10.35	– Shiprock – Four Corners Project 345 kV Switchyard Interconnection Agreement, dated March 6, 2002. APS Contract No. 51999. (Exhibit 10.06 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2002)
10.36	– Interconnection Agreement dated as of May 23, 2002, between the Company and the Public Service Company of New Mexico. (Exhibit 10.09 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2002)
10.36-01	– First Amended and Restated Interconnection Agreement, dated October 9, 2003, to Exhibit 10.36. (Exhibit 10.52.01 to the Company's Annual Report on Form 10-K for the year ended December 31, 2003)
10.37	– Reserved

INDEX TO EXHIBITS

Exhibit Number	Title
10.38	– Credit agreement dated as of April 11, 2006, among the Company, JPMorgan Chase Bank, N.A., not in its individual capacity, but solely in its capacity as trustee of the Rio Grande Resources Trust II, the lenders party hereto, JPMorgan Chase Bank, N.A., as administrative agent and issuing bank and Union Bank of California, N.A., as syndication agent. (Exhibit 10.01 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2006)
10.38-01	– Incremental Facility Assumption Agreement, dated as of July 12, 2007, related to the Credit Agreement referred to in Exhibit 10.38 to the Company's Annual Report on Form 10-K for the year ended December 31, 2006. (Exhibit 10.10 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2007)
10.39	– Eight Treasury Rate Lock agreements between the Company and Credit Suisse First Boston International. (Exhibit 10.02 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2005)
†††††10.40	– Master Power Purchase and Sale Agreement and Transaction Agreement, dated as of July 7, 2004, between the Company and Southwestern Public Service Company. (Exhibit 10.03 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2005)
10.41	– Rate Agreement between the Company and the City of El Paso, Texas, dated as of July 1, 2005.
10.42	– Power Purchase and Sale Agreement, dated as of December 16, 2005, between the Company and Phelps Dodge Energy Services, LLC. (Exhibit 10.42 to the Company's Annual Report on Form 10-K for the year ended December 31, 2005)
10.43	– Settlement Agreement between the State of Texas and the Company, dated as of October 17, 2006. (Exhibit 10.08 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2006)
†††††10.44	– Confirmation of Power Purchase Transaction, dated April 18, 2007, between the Company and Credit Suisse Energy LLC. (Exhibit 10.03 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2007)
†††††10.45	– Confirmation of Power Sales Transaction, dated April 18, 2007, between the Company and Imperial Irrigation District. (Exhibit 10.04 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2007)
10.46	– Employment Agreement between the Company and Ershel C. Redd, Jr. (Exhibit 10.1 to the Company's Form 8-K, dated May 15, 2007)
10.47	– Separation Agreement between the Company and Gary R. Hedrick. (Exhibit 10.2 to the Company's Form 8-K, dated as of May 15, 2007)
10.48	– El Paso Electric Company 2007 Long-Term Incentive Plan. (Exhibit 10.1 to the Company's Form 8-K, dated as of May 2, 2007)

INDEX TO EXHIBITS

Exhibit Number	Title
10.49	– Lease, dated as of June 1, 2007, between the Company and 100 North Stanton Tower LLC. (Exhibit 10.11 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2007)
Exhibit 21 – Subsidiaries of the Company:	
21.01	– MiraSol Energy Services, Inc., a Delaware corporation
Exhibit 23 – Consent of Experts:	
*23.01	– Consent of KPMG LLP (set forth on page 141 of this report)
Exhibit 24 – Power of Attorney:	
*24.01	– Power of Attorney (set forth on page 140 of the Original Form 10-K)
*24.02	– Certified copy of resolution authorizing signatures pursuant to power of attorney
Exhibit 31 and 32 – Certifications:	
*31.01	– Certifications pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
*32.01	– Certifications pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
Exhibit 99 – Additional Exhibits:	
99.01	– Agreed Order, entered August 30, 1995, by the Public Utility Commission of Texas. (Exhibit 99.31 to Registration Statement No. 33-99744 on Form S-1)
99.02	– Reserved
99.03	– Final Order, entered September 24, 1998, by the New Mexico Public Utility Commission. (Exhibit 99.31 to the Company's Annual Report on Form 10-K for the year ended December 31, 1998)
99.04	– Final Order, entered June 8, 1999, by the Public Utility Commission of Texas. (Exhibit 99.01 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 1999)
99.05	– Final Order, entered January 8, 2002, by the New Mexico Public Utility Commission. (Exhibit 99.05 to the Company's Annual Report on Form 10-K for the year ended December 31, 2002)
99.06	– News Release, dated as of December 5, 2002, by the El Paso Electric Company announcing settlement with the FERC Trial Staff. (Exhibit 99.01 to the Company's Form 8-K, dated as of December 6, 2002)

INDEX TO EXHIBITS

Exhibit Number	Title
99.07	– "Stipulated Facts and Remedies," dated as of December 5, 2002, to be filed by the FERC Trial Staff as part of its written testimony. (Exhibit 99.02 to the Company's Form 8-K, dated as of December 6, 2002)

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* Filed herewith.

† Fifteen agreements, substantially identical in all material respects to this exhibit, have been entered into with Gary R. Hedrick; J. Frank Bates; Scott D. Wilson; Steven P. Busser; David G. Carpenter; Robert C. Doyle; Fernando J. Gireud; Hector Gutierrez, Jr.; Helen Knopp; Kerry B. Lore; Hector R. Puente; Andres Ramirez; Gary Sanders; Guillermo Silva, Jr.; and John A. Whitacre; officers of the Company.

†† Two agreements, dated January 3, 1998, identical in all material respects to this Exhibit, have been entered into with J. Frank Bates and Gary R. Hedrick; officers of the Company.

One agreement, dated as of May 28, 1999, identical in all material respects to this Exhibit, has been entered into with Helen Knopp; officer of the Company.

One agreement, dated as of January 3, 2000, identical in all material respects to this Exhibit, has been entered into with John C. Horne; officer of the Company.

One agreement, dated as of April 23, 2001, identical in all material respects to this Exhibit, has been entered into with Hector Puente; officer of the Company.

One agreement, dated as of November 5, 2001, identical in all material respects to this Exhibit, has been entered into with Gary R. Hedrick; officer of the Company.

One agreement, dated as of November 26, 2001, identical in all material respects to this Exhibit, has been entered into with J. Frank Bates; officer of the Company.

Three agreements, dated as of May 10, 2001, identical in all material respects to this Exhibit, have been entered into with Kathryn Hood, Kerry B. Lore and Guillermo Silva, Jr.; officers of the Company.

Two agreements, dated as of July 15, 2002, identical in all material respects to this Exhibit, have been entered into with Fernando J. Gireud and John A. Whitacre; officers of the Company.

Two agreements, dated as of December 4, 2003, identical in all material respects to this Exhibit, have been entered into with Steven P. Busser and Scott D. Wilson; officers of the Company.

††† In lieu of non-employee director cash compensation, four agreements, dated as of January 1, 2006 and April 1, 2006, substantially identical in all material respects to this Exhibit, have been entered into with Kenneth R. Heitz; and Patricia Z. Holland-Branch; directors of the Company.

INDEX TO EXHIBITS

Exhibit Number	Title
	In lieu of non-employee director cash compensation, eleven agreements, dated as of May 3, 2006, substantially identical in all material respects to this Exhibit, were entered into with J. Robert Brown; James W. Cicconi; George W. Edwards, Jr.; Ramiro Guzman; James W. Harris; Kenneth R. Heitz; Patricia Z. Holland-Branch; Michael K. Parks; Eric B. Siegel; Stephen N. Wertheimer; and Charles A. Yamarone; directors of the Company.
	In lieu of non-employee director cash compensation, six agreements, dated as of July 1, 2006, October 1, 2006 and January 1, 2007, substantially identical in all material respects to this Exhibit, have been entered into with Kenneth R. Heitz; and Patricia Z. Holland-Branch; directors of the Company.
	In lieu of non-employee director cash compensation, six agreements, dated as of April 1, 2007, July 1, 2007 and October 1, 2007, substantially identical in all material respects to this Exhibit, have been entered into with Kenneth R. Heitz; and Patricia Z. Holland-Branch; directors of the Company.
	In lieu of non-employee director cash compensation, eleven agreements, dated as of May 2, 2007, substantially identical in all material respects to this Exhibit, were entered into with J. Robert Brown; James W. Cicconi; George W. Edwards, Jr.; Ramiro Guzman; James W. Harris; Kenneth R. Heitz; Patricia Z. Holland-Branch; Michael K. Parks; Eric B. Siegel; Stephen N. Wertheimer; and Charles A. Yamarone; directors of the Company.
††††	Eight agreements, dated as of May 8, 1997, identical in all material respects to this Exhibit have been entered into with George W. Edwards, Jr.; Ramiro Guzman; James W. Harris; Kenneth R. Heitz; Michael K. Parks; Eric B. Siegel; Stephen N. Wertheimer and Charles A. Yamarone; directors of the Company.
	Ten agreements, dated as of May 29, 1998, identical in all material respects to this Exhibit have been entered into with George W. Edwards, Jr.; James W. Cicconi; Ramiro Guzman; James W. Harris; Kenneth R. Heitz; Patricia Z. Holland-Branch; Michael K. Parks; Eric B. Siegel; Stephen N. Wertheimer and Charles A. Yamarone; directors of the Company.
	In lieu of non-employee director cash compensation, two agreements, dated as of July 1, 2002 and October 1, 2002, substantially identical in all material respects to this Exhibit, have been entered into with Kenneth Heitz; director of the Company.
	In lieu of non-employee director cash compensation, two agreements, dated as of January 1, 2003 and April 1, 2003, substantially identical in all material respects to this Exhibit, have been entered into with Kenneth Heitz; director of the Company.
†††††	Confidential treatment has been requested and received for the redacted portions of these Exhibits. The copies filed omit the information subject to the confidentiality request. Omissions are designated as "****." A complete version of these Exhibits has been filed separately with the Securities and Exchange Commission.

UNDERTAKING

Insofar as indemnification for liabilities arising under the Securities Act of 1933 may be permitted to directors, officers and controlling persons of the registrant pursuant to the foregoing provisions, or otherwise, the registrant has been advised that in the opinion of the Securities and Exchange Commission such indemnification is against public policy as expressed in the Securities Act of 1933 and is, therefore, unenforceable. In the event that a claim for indemnification against such liabilities (other than the payment by the registrant of expenses incurred or paid by a director, officer or controlling person of the registrant in the successful defense of any action, suit or proceeding) is asserted by such director, officer or controlling person in connection with the securities being registered, the registrant will, unless in the opinion of its counsel the matter has been settled by controlling precedent, submit to a court of appropriate jurisdiction the question of whether such indemnification by it is against public policy as expressed in the Act and will be governed by the final adjudication of such issue.

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS, that each of El Paso Electric Company, a Texas corporation, and the undersigned directors and officers of El Paso Electric Company, hereby constitutes and appoints J. Frank Bates, Scott D. Wilson, and Gary D. Sanders, its, his or her true and lawful attorneys-in-fact and agents, for it, him or her and its, his or her name, place and stead, in any and all capacities, with full power to act alone, to sign this report and any and all amendments to this report, and to file each such amendment to this report, with all exhibits thereto, and any and all documents in connection therewith, with the Securities and Exchange Commission, hereby granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform any and all acts and things requisite and necessary to be done in and about the premises, as fully to all intents and purposes as it, he or she might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them, may lawfully do or cause to be done by virtue hereof.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on the 29th day of February 2008.

EL PASO ELECTRIC COMPANY

By: **/s/ J. FRANK BATES**
J. Frank Bates
Interim President and Chief Executive Officer
(Principal Executive Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the date indicated.

Signature	Title	Date
/s/ J. FRANK BATES (J. Frank Bates)	Interim President and Chief Executive Officer (Principal Executive Officer)	February 29, 2008
/s/ SCOTT D. WILSON (Scott D. Wilson)	Executive Vice President, Chief Financial and Chief Administrative Officer (Principal Financial Officer)	
/s/ DAVID G. CARPENTER (David G. Carpenter)	Vice President, Corporate Planning and Controller	
/s/ J. ROBERT BROWN (J. Robert Brown)	Director	
/s/ JAMES W. CICCONI (James W. Cicconi)	Director	
/s/ GEORGE W. EDWARDS, JR. (George W. Edwards, Jr.)	Director	
/s/ RAMIRO GUZMAN (Ramiro Guzman)	Director	
/s/ JAMES W. HARRIS (James W. Harris)	Director	
/s/ GARY R. HEDRICK (Gary R. Hedrick)	Director	
/s/ KENNETH R. HEITZ (Kenneth R. Heitz)	Director	
/s/ PATRICIA Z. HOLLAND-BRANCH (Patricia Z. Holland-Branch)	Director	
/s/ MICHAEL K. PARKS (Michael K. Parks)	Director	
/s/ ERIC B. SIEGEL (Eric B. Siegel)	Director	
/s/ STEPHEN N. WERTHEIMER (Stephen N. Wertheimer)	Director	
/s/ CHARLES A. YAMARONE (Charles A. Yamarone)	Director	

EXHIBIT 23.01

Consent of Independent Registered Public Accounting Firm

The Board of Directors
El Paso Electric Company:

We consent to the incorporation by reference in the registration statements (Nos. 333-17971, 333-82129, 333-123646, and 333-142557) on Form S-8 of El Paso Electric Company of our report dated February 28, 2008, with respect to the consolidated balance sheets of El Paso Electric Company and subsidiary as of December 31, 2007 and 2006, and the related consolidated statements of operations, comprehensive operations, changes in common stock equity, and cash flows for each of the years in the three-year period ended December 31, 2007, which report appears in the December 31, 2007 annual report on Form 10-K of El Paso Electric Company. Our report on the consolidated financial statements refers to changes in the Company's accounting for asset retirement obligations in 2005, defined benefit pension and other postretirement plans and share-based payments in 2006, and uncertainty in income taxes in 2007.

KPMG LLP

Houston, Texas
February 28, 2008