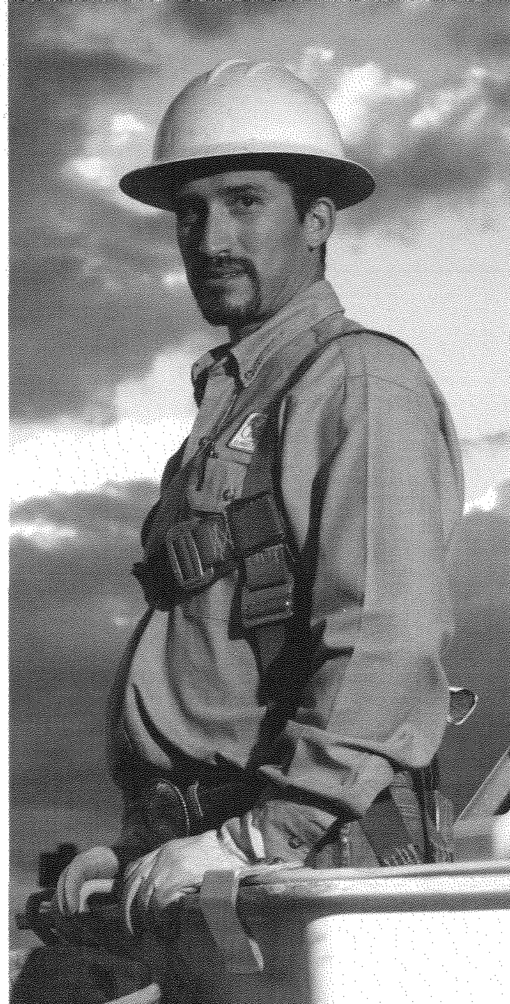
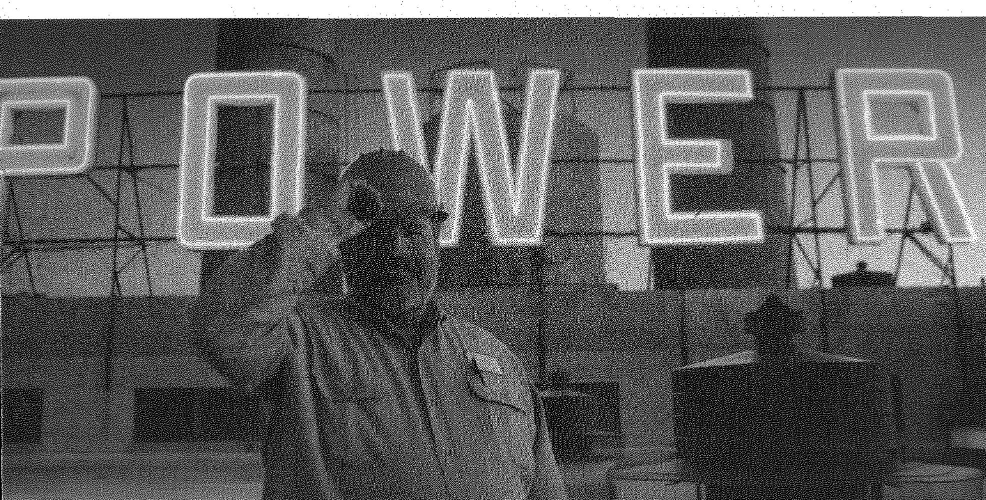




el paso
electric
2010 annual report

Front cover, clockwise from top:

Travis Gonzales, Apprentice Lineman

Jennifer Borden, Manager — Regulatory Accounting & Compliance

Ernie Aguilar, Lineman

Linda Montes, Representative — Customer Service

Back cover, clockwise from top:

Loren Barela, Apprentice Lineman

Linda Pleasant, Specialist Principal Rate Analyst

Ruth Uro, Senior Office Dispatch Coordinator

David Aranda, Superintendent — Plant Operations

Rose Lowe, Senior Consultant — Customer Contact

dear shareholders:

In 2010, El Paso Electric Company (EE) continued to fulfill our commitments to customers and shareholders and to position ourselves to meet the energy demands of our growing customer base. This past year, we added new generation, expanded our transmission and distribution infrastructure, and made other significant capital investments. We have also maintained a strong financial foundation, which allowed us to continue to enhance the services we provide to our customers while still providing long-term value to our shareholders.

For the year, our stock price rose 36 percent and ended the year at $27.53 per share, making EE the best-performing investor-owned utility stock on Edison Electric Institute's index of utility companies. In comparison, the S&P 500 Utilities Total Return Index and the Dow Jones Industrial Average Total Return Index posted returns of 15 percent and 14 percent, respectively. While we are very pleased with our stock's performance, our goal remains to provide value to our shareholders by providing value and service to our customers.

... our goal remains to provide value to our shareholders by providing value and service to our customers.

To that end, we are focused on maintaining a strong balance sheet. Our shareholders' equity represented 49 percent of our capitalization at year-end. We repurchased approximately 1.5 million shares of common stock during the year at a total cost of $33.7 million, and our stock repurchases have averaged 3.55 percent of the outstanding shares each year since the inception of our buyback program back in 1999.

On March 21, 2011, we announced our intention to commence paying a quarterly cash dividend of $0.22 per share beginning in the second quarter of 2011. In addition, the Board of Directors authorized the repurchase of an additional 2.5 million shares of common stock under our share repurchase program. Our new dividend policy, in addition to our share repurchase program, demonstrates our commitment to return value to our shareholders.

In 2010, we filed and concluded our first rate case in Texas in more than 15 years. We reached a unanimous settlement with all parties in the case, culminating in the issuance of a final order by the Public Utility Commission of Texas (PUCT) on July 30, 2010, approving the settlement. The resolution of this rate case removed regulatory uncertainty while giving us the opportunity to earn a fair return for shareholders. In addition to our new rates in Texas, we also implemented the previously approved rates in New Mexico in January 2010.


Rose Lowe, Senior Consultant — Customer Contact

This past year, we also delivered solid financial results. We increased our earnings per share by almost 39 percent from $1.50 per basic share in 2009 to $2.08 per basic share (before an extraordinary gain) in 2010. Our 2010 earnings were positively impacted by increased retail kWh sales, an expanding customer base, improving local economic conditions, and modest rate increases in both our operating jurisdictions, which reflected the cost of capital investments made to meet the growth in our service territory. During 2010, every segment of our retail business posted revenue growth. We continue to experience robust kWh sales and customer growth as a result of our growing local economy, including the significant ongoing expansion at Fort Bliss. Over the past five years, our retail kWh sales have grown at a compound annual rate of 2.25 percent, which significantly exceeds the five-year national industry average kWh sales growth rate of 0.42 percent.

Other important financial accomplishments in 2010 include enhancing the quality of our balance sheet by completing a $110 million private placement of senior notes to finance nuclear fuel in August 2010 and by refinancing our $200 million revolving credit facility in September 2010. Both of these financial transactions have significantly increased our liquidity position and will provide additional financing flexibility in the future.

In 2010, we also achieved major operational accomplishments. We reached a record native system peak of 1,616 MW on August 23, 2010, which surpassed the previous native system peak of 1,571 MW set on July 15, 2009. Our solid growth in demand and our expanding customer base underscore our need for new generation resources to meet future load growth and to replace our older gas-fired units, along with enhancing our transmission and distribution infrastructure.

Another important achievement in 2010 was entering into a new three-year contract with the International Brotherhood of Electrical Workers Local 960 in September 2010. We continue to be proud of our relationship with the Union, as well as with all of our employees.

We also continually strive to identify ways to improve the level of service we provide to our customers. In furtherance of this objective, we successfully implemented a new customer care and billing system in 2010, which included a re-engineering of our customer care and billing processes.

In 2010, the Palo Verde Nuclear Generating Station (Palo Verde) was again our largest single source of generation, providing clean energy and representing 45 percent of our energy mix. Palo Verde was also the largest power producer in the

Travis Gonzales, Apprentice Lineman

United States during 2010, with more than 31 million MWhs generated (total plant) and a capacity factor of 90.4 percent. Palo Verde recently achieved a major milestone regarding its application for a 20-year license extension that was filed with the Nuclear Regulatory Commission (NRC) in December 2008. After working diligently with the NRC for the past two years, Palo Verde recently obtained favorable safety and environmental reports from the NRC.

We continue to increase our renewable energy capacity in New Mexico. Through purchase power agreements with various solar energy producers, El Paso Electric expects to have about 50 MW of new solar energy capacity available by the end of 2012. The solar projects expected to be completed in 2011 and 2012 include ...

- A 5 MW photovoltaic facility in Hatch, N.M., with commercial operation expected in the summer of 2011
- A 20 MW photovoltaic facility in Santa Teresa, N.M., with commercial operation expected in the fourth quarter of 2011
- A 12 MW photovoltaic facility in Las Cruces, N.M., with commercial operation expected by the end of 2011
- A 12 MW photovoltaic facility in Chaparral, N.M., with commercial operation expected in 2012

EE issued a request for proposal for an additional 5 to 15 MW of biomass, biofuel, geothermal or landfill gas generating capacity to meet its New Mexico biomass requirements starting in 2014. Finally, EE has committed $10 million to build solar energy projects and conduct renewable energy research within its Texas service territory. Through this initiative, we hope to create partnerships to advance renewable energy projects and promote economic development in El Paso.

In 2011, we will continue to focus on initiatives and opportunities that meet the needs of our stakeholders and provide long-term shareholder value. We will be focusing on the completion of Phase II of Newman 5, which, through the addition of the two heat recovery steam generators and a steam turbine, will increase plant capacity by 148 MW. Currently, this project remains under budget and on schedule for completion in April of 2011.

... we will continue to focus on **initiatives** and **opportunities** that meet the needs of our stakeholders and provide **long-term** shareholder **value.**

We will continue to make capital investments to meet our customer growth and to enhance our operations. Over the next four years, we expect to make capital investments of approximately $834 million, or an average of $209 million annually, primarily for new generation, the expansion and updating of our transmission and distribution infrastructure, and capital improvements at Palo Verde. In 2011, we will seek regulatory approval to add an 87 MW aeroderivative peaking unit at our Rio Grande site. The second phase of Newman 5 and the new unit at the Rio Grande site will enable us to meet our growing load requirements and to continue to provide reliable service to our customers. For 11 out of the past 12 years, EE's distribution system has received top marks on the system reliability indices tracked by the PUCT. In 2010, through the hard work of our employees, we had the best "System Average Interruption Frequency" ranking among Texas investor-owned utilities and the second-best "System Average Interruption Duration Index" ranking. Finally, we will remain focused on our return on equity, both actual and projected, to determine the timing of future rate cases. Currently, we do not anticipate the need to file a rate case in either Texas or New Mexico during 2011.

Throughout 2010, our employees continued their support of and involvement with the communities we serve. Our employees logged more than 14,000 volunteer hours and donated more than $163,000 to the United Way. Our employees also demonstrated a commitment to our business and customers and worked extremely hard to keep El Paso Electric one of the most reliable electric utilities in the Southwest.

Our financial and operational accomplishments during 2010 highlight the growth of our core business and our strong fiscal discipline. El Paso Electric continues to provide value, not only for the communities and customers we serve, but also for you — our shareholders. Thank you for your continued support and confidence.

David W. Stevens
Chief Executive Officer

Kenneth R. Heitz
Chairman of the Board

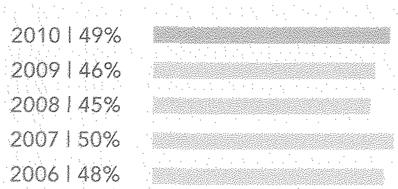
Center: Linda Pleasant, Specialist Principal Rate Analyst
Right: Ruth Uro, Senior Officer Dispatch Coordinator

2010 performance highlights

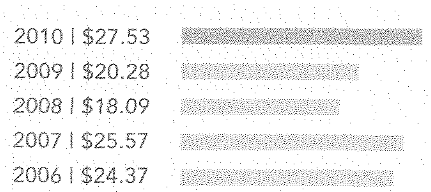
Financial ($000)	2008	2009	2010
Operating Revenues			
Retail Non-Fuel Base Revenues	$ 470,138	$ 483,300	$ 536,309
Deregulated Palo Verde Unit 3 Proxy Market Pricing	$ 25,446	$ 14,143	$ 16,103
Off-System Sales Gross Margins	$ 29,479	$ 14,399	$ 11,801
Retained Margins	$ 22,137	$ 10,803	$ 5,687
Net Income (before extraordinary item)	$ 77,621	$ 66,933	$ 90,317 (a)
Total Assets	$ 2,069,083	$ 2,226,152	$ 2,364,766
Common Stock Data			
Earnings Per Share (income before extraordinary item) (diluted weighted average)	$ 1.72	$ 1.50	$ 2.07
Market Price Per Share (year-end close)	$ 18.09	$ 20.28	$ 27.53
Book Value Per Share	$ 15.47	$ 16.45	$ 19.04
Weighted Average Number of Shares & Dilutive Potential Shares Outstanding	44,930,109	44,595,067	43,294,419
Number of Registered Holders as of 12/31	3,687	3,577	3,453

(a) 2010 earnings include a one-time non-cash charge of $4.8 million or $0.11 per share related to recognizing a change in the tax law included in the health-reform legislation, which eliminated the tax benefit of Medicare Part D subsidies.

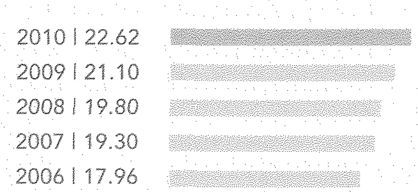
Common Stock Equity
(percent of capitalization)



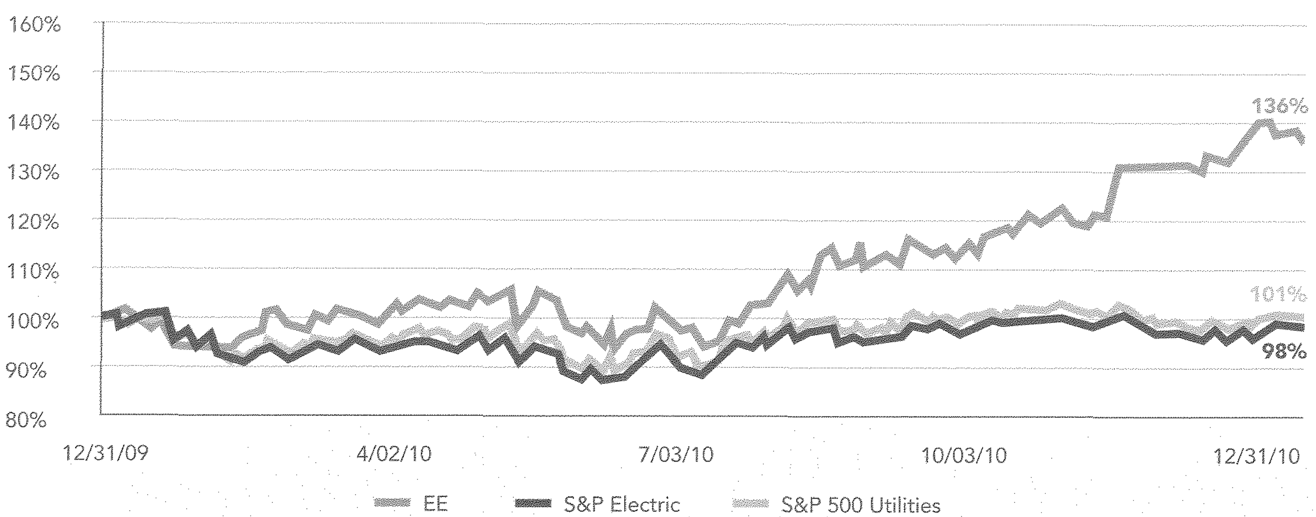
Market Price Per Share
(year-end)



Cumulative Share Repurchases
(in millions)

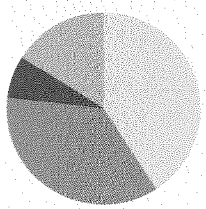


Relative Price Performance El Paso Electric vs. S&P Electric and S&P 500 Utilities Indices
12/31/09–12/31/10



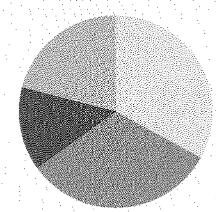
2010 Retail Non-Fuel Base Operating Revenues

Residential | 41%
Commercial & Ind. Small | 35%
Commercial & Ind. Large | 8%
Sales to Public Authorities | 16%



2010 Retail MWh Sales

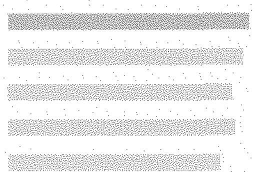
Residential | 34%
Commercial & Ind. Small | 31%
Commercial & Ind. Large | 14%
Sales to Public Authorities | 21%



2010 operational highlights

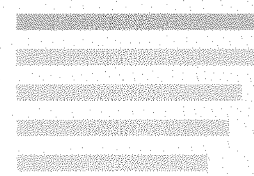
Customers Served Per Employee

2010 | 395
2009 | 385
2008 | 367
2007 | 372
2006 | 348



Palo Verde Capacity Factors

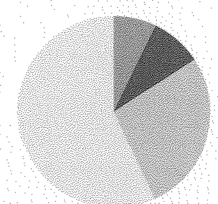
2010 | 90%
2009 | 89%
2008 | 84%
2007 | 79%
2006 | 71%



Operational	2008	2009	2010
Retail GWh Sold	7,034	7,120	7,434
% Change	0.07%	1.22%	4.41%
Native Peak (MW)	1,524	1,571	1,616
Customers at Year-End	363,452	369,871	376,822
% Change	1.77%	1.77%	1.88%
Employees at Year-End	989	961	954

2011–2014 Estimated Construction Costs
(in millions)

Production | $474 (1)(2)
Transmission | $60
General | $72
Distribution | $228



Generating Capacity

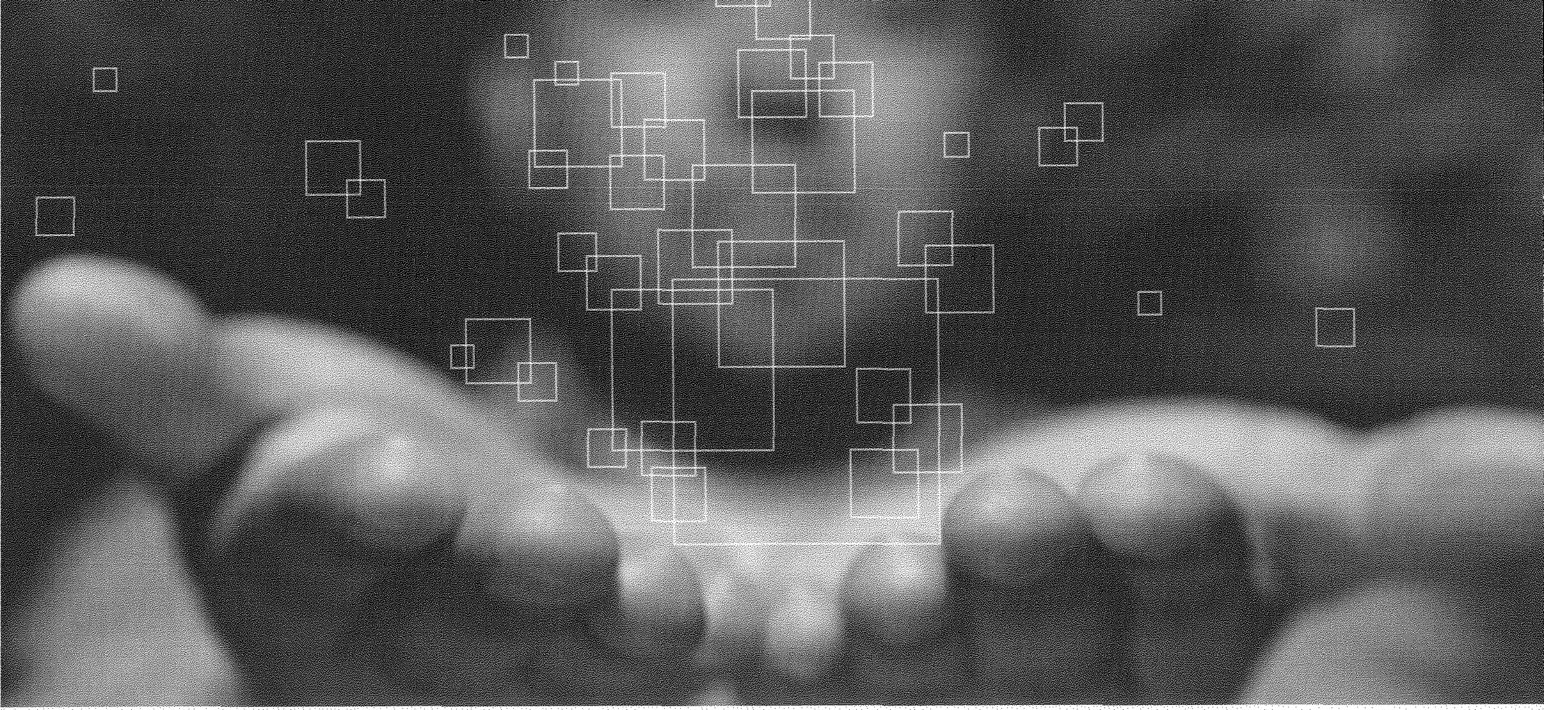
Plant	Net Dependable Generating Capability	Fuel Source	Energy Mix
Palo Verde	633 MW	Nuclear	45%
Newman	614 MW	Natural Gas	
Rio Grande	229 MW	Natural Gas	27%
Copper	62 MW	Natural Gas	
Four Corners	104 MW	Coal	6%
		Purchased Power	22%
Hueco Mountain Wind Ranch	1 MW	Wind	
Total	**1,643 MW**		**100%**

(1) Does not include acquisition costs for nuclear fuel.
(2) Includes $289 million for new generating capacity, of which $19 million is allocated for the completion of Newman 5, $73 million for an 87 MW peaking unit at the Rio Grande Station, $174 million for a new 290 MW combined cycle unit, $11 million for anticipated renewable projects, and $12 million for other generation projects.

operating statistics

Operating Revenues (in thousands):	2010	2009	2008	2007
Non-Fuel Base Revenues:				
Retail:				
Residential	$217,615	$195,798	$184,800	$184,562
Commercial and Industrial, Small	188,390	175,328	174,593	168,091
Commercial and Industrial, Large	43,844	34,804	36,318	39,092
Sales to Public Authorities	86,460	77,370	74,427	72,763
Total Retail Base Revenues	536,309	483,300	470,138	464,508
Wholesale:				
Sales for Resale	1,943	2,037	1,646	1,919
Total Non-Fuel Base Revenues	538,252	485,337	471,784	466,427
Fuel Revenues:				
Recovered from customers during the period	170,588	196,081	198,292	197,383
Under (over) collection of fuel	(35,408)	(66,608)	42,752	17,828
New Mexico Fuel in Base Rates	71,876	69,026	68,631	51,487
Total Fuel Revenues	207,056	198,499	309,675	266,698
Off-System (Economy) Sales	105,317	116,064	232,500	125,974
Other	26,626	28,096	24,971	18,328
Total Operating Revenues	$877,251	$827,996	$1,038,930	$877,427
Number of Customers (end of year):				
Residential	334,729	328,553	322,618	317,091
Commercial and Industrial, Small	37,202	36,306	35,850	35,147
Commercial and Industrial, Large	50	48	49	53
Other	4,841	4,964	4,935	4,853
Total	376,822	369,871	363,452	357,144
Average annual kWh use per residential customer	**7,560**	**7,244**	**6,955**	**7,085**
Energy Sales, MWh:				
Generated	8,465,659	7,979,290	8,023,475	7,707,095
Purchased and Interchanged	2,420,869	2,745,500	3,152,396	2,188,904
Total Energy Supplied	10,886,528	10,724,790	11,175,871	9,895,999
Energy Sales, MWh:				
Retail:				
Residential	2,508,834	2,361,650	2,227,838	2,232,668
Commercial and Industrial, Small	2,295,537	2,251,399	2,255,585	2,216,428
Commercial and Industrial, Large	1,087,413	1,024,186	1,102,277	1,195,038
Sales to Public Authorities	1,542,389	1,482,448	1,448,654	1,384,380
Total Retail	7,434,173	7,119,683	7,034,354	7,028,514
Wholesale:				
Sales for Resale	53,637	56,931	50,148	48,290
Off-System (Economy) Sales	2,822,732	2,995,984	3,506,770	2,201,294
Total Wholesale	2,876,369	3,052,915	3,556,918	2,249,584
Total Energy Sales	10,310,542	10,172,598	10,591,272	9,278,098
Losses and Company Use	575,986	552,192	584,599	617,901
Total, Net	10,886,528	10,724,790	11,175,871	9,895,999
Native System:				
Peak Load, MW	1,616	1,571	1,524	1,508
Net Dependable Generating Capability for Peak, MW	1,643	1,643	1,503	1,492
Total System:				
Peak Load, MW	1,889	1,723	1,669	1,680
Net Dependable Generating Capability for Peak, MW	1,643	1,643	1,503	1,492

2006	2005	2004	2003	2002	2001
$175,641	$173,007	$164,791	$161,852	$157,122	$150,524
161,359	158,406	157,188	156,869	155,311	154,012
40,502	39,192	41,096	41,402	41,657	42,091
68,438	65,861	65,351	65,830	63,908	63,430
445,940	436,466	428,426	425,953	417,998	410,057
1,794	1,687	1,675	3,223	32,228	52,879
447,734	438,153	430,101	429,176	450,226	462,936
225,441	164,500	143,692	135,956	153,141	162,758
(3,655)	79,539	17,360	(13,195)	5,509	1,577
30,033	29,440	27,956	27,370	26,096	25,219
251,819	273,479	189,008	150,131	184,746	189,554
95,932	78,209	78,533	76,536	43,654	92,452
20,970	14,072	10,986	8,519	11,459	24,763
$816,455	$803,913	$708,628	$664,362	$690,085	$769,705
311,923	304,031	296,435	289,179	281,874	276,200
32,950	31,969	31,079	30,254	29,281	28,573
58	61	58	63	64	65
4,800	4,792	4,553	4,524	4,431	4,308
349,731	340,853	332,125	324,020	315,650	309,146
6,852	**6,936**	**6,769**	**6,761**	**6,694**	**6,529**
6,908,006	7,500,144	7,611,455	7,740,923	7,785,938	8,183,713
2,208,661	1,255,626	1,410,114	1,250,707	1,549,875	951,359
9,116,667	8,755,770	9,021,569	8,991,630	9,335,813	9,135,072
2,113,733	2,090,098	1,986,085	1,932,171	1,870,931	1,789,199
2,159,599	2,126,918	2,115,822	2,096,860	2,076,758	2,069,517
1,204,707	1,165,506	1,236,426	1,197,065	1,161,815	1,174,235
1,343,129	1,270,116	1,243,003	1,224,349	1,212,180	1,185,521
6,821,168	6,652,638	6,581,336	6,450,445	6,321,684	6,218,472
45,397	41,883	41,094	67,754	986,134	1,460,383
1,635,407	1,420,778	1,838,467	1,920,882	1,483,465	929,914
1,680,804	1,462,661	1,879,561	1,988,636	2,469,599	2,390,297
8,501,972	8,115,299	8,460,897	8,439,081	8,791,283	8,608,769
614,695	640,471	560,672	552,549	544,530	526,303
9,116,667	8,755,770	9,021,569	8,991,630	9,335,813	9,135,072
1,428	1,376	1,332	1,308	1,282	1,199
1,492	1,479	1,472	1,459	1,466	1,466
1,675	1,628	1,575	1,546	1,509	1,485
1,492	1,479	1,472	1,459	1,466	1,466



investor relations

Securities and Records

The common stock of El Paso Electric is traded on the New York Stock Exchange. The ticker symbol is EE. EE and BNY Mellon act as co-registrars for EE's common stock. BNY Mellon maintains all shareholder records of EE.

Form 10-K Report and Shareholder Inquiries

A complete copy of *EE's Annual Report and Form 10-K for the year ending December 31, 2010, which has been filed with the Securities* and Exchange Commission, including financial statements and financial statement schedules, is available without charge upon written request to:

Investor Relations

El Paso Electric
P.O. Box 982
El Paso, TX 79960
Call: (800) 592-1634
E-mail: investor_relations@epelectric.com
Website: epelectric.com

Shareowner Services

Shareholders may obtain information relating to their share position, transfer requirements, lost certificates and other related matters by contacting BNY Mellon Shareowner Services at (866) 202-2682 (inside the United States and Canada), (201) 680-6578 (outside the United States and Canada), or (800) 231-5469 (TDD) for the hearing impaired. The phone service is available to all shareholders Monday through Friday, 8 a.m. to 8 p.m., EST.
Website: bnymellon.com/shareowner/isd

Address shareowner inquiries to:

El Paso Electric Company
C/O BNY Mellon Shareowner Services
P.O. Box 358015
Pittsburgh, PA 15252-8015

board of directors

Kenneth R. Heitz
Chairman of the Board
Partner, Irell & Manella, LLP
Los Angeles, CA

Michael K. Parks
Vice Chairman of the Board
Managing Director, TCW Group
Los Angeles, CA

Catherine A. Allen
Chairman and Chief Executive Officer
The Santa Fe Group
Santa Fe, NM

J. Robert Brown
Owner and President
Brownco Capital, LLC
El Paso, TX

James W. Cicconi
Senior Executive Vice President
External and Legislative Affairs
AT&T
Washington, D.C.

James W. Harris
Founder and President
Seneca Financial Group, Inc.
Greenwich, CT

Patricia Z. Holland-Branch
Chief Executive Officer and Owner
Facilities Connection, Inc.
El Paso, TX

Thomas V. Shockley
Retired Vice Chairman
and Chief Operating Officer
American Electric Power, Inc.
Columbus, OH

Eric B. Siegel
Retired Limited Partner of Apollo Advisors, LP
Consultant and Special Advisor to the
Chairman, Milwaukee Brewers Baseball Club
Los Angeles, CA

David W. Stevens
Chief Executive Officer
El Paso Electric Company
El Paso, TX

Stephen N. Wertheimer
Managing Director and Founding Partner
W Capital Partners
New York, NY

Charles A. Yamarone
Director
Houlihan Lokey
Los Angeles, CA

officers

David W. Stevens
Chief Executive Officer

David G. Carpenter
Senior Vice President
Chief Financial Officer

Richard Fleager
Senior Vice President
Customer Care and External Affairs

Mary E. Kipp
Senior Vice President
General Counsel and
Chief Compliance Officer

Rocky Miracle
Senior Vice President
Corporate Planning and Development

Steve Buraczyk
Vice President
System Operations and Planning

Steven P. Busser
Vice President
Treasurer

Robert Clay Doyle
Vice President
New Mexico Affairs

Nathan T. Hirschi
Vice President
and Controller

Kerry B. Lore
Vice President
Customer Care

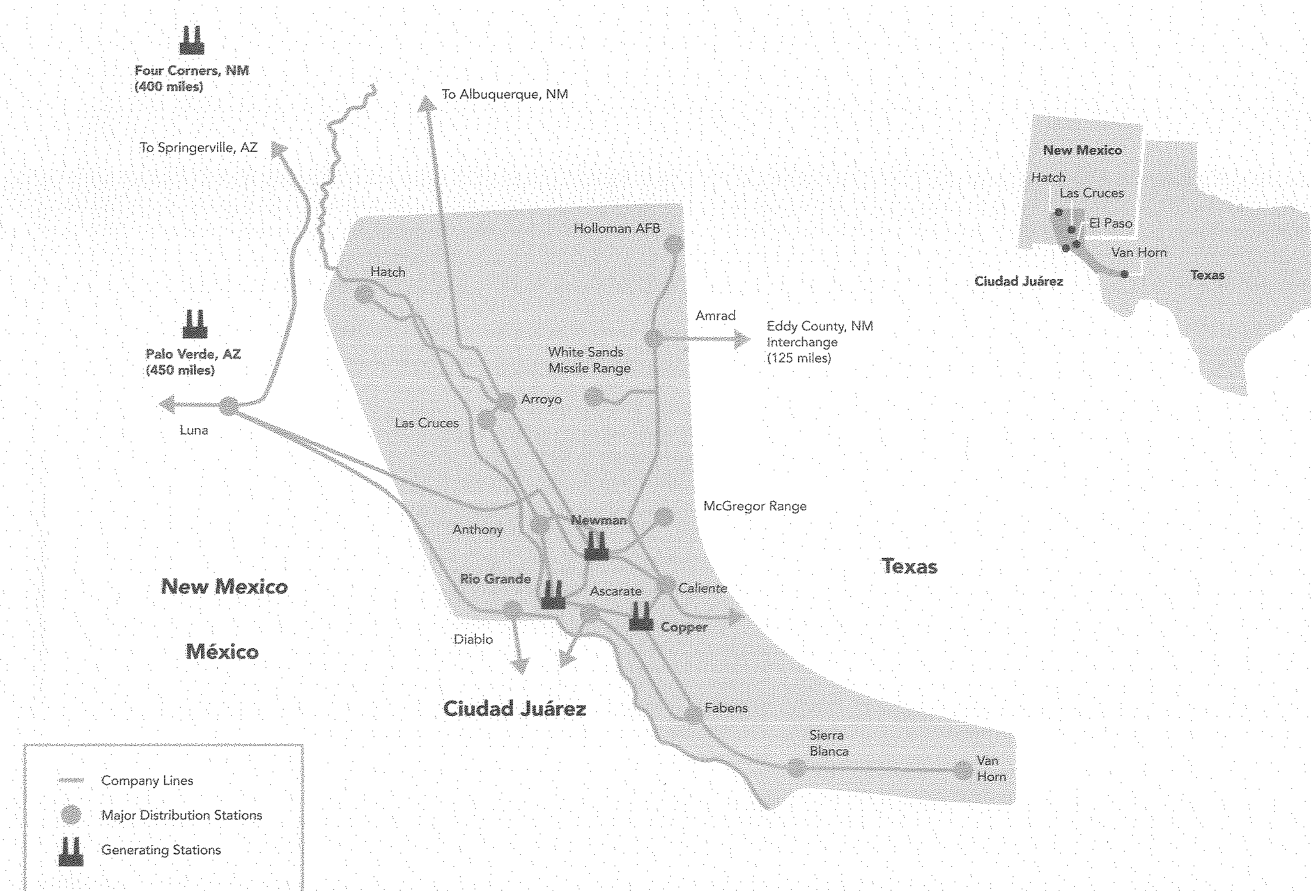
Hector R. Puente
Vice President
Transmission and Distribution

Andy Ramirez
Vice President
Power Generation

Guillermo Silva, Jr.
Corporate Secretary

John A. Whitacre
Vice President
Power Marketing and Fuels

service area



Statements in this annual report, other than statements of historical information, are forward-looking statements that are made pursuant to the safe-harbor provisions of the Private Securities Litigation Reform Act of 1995 (the "act"). Such statements are intended to be made as of the date of this document, and the Company does not undertake to update any such forward-looking statement. Forward-looking statements involve known and unknown risks and other factors that may cause actual results to differ materially from those expressed in this document. In connection with the safe-harbor provisions of the act, the Company has set forth below a number of important risks and factors that could cause actual results to differ materially from forward-looking information. Factors that could cause or contribute to such differences include, but are not limited to:

- Increased prices for fuel and purchased power and the possibility that regulators may not permit El Paso Electric (EE) to pass through all such increased costs to customers or to recover previously incurred fuel costs in rates
- Recovery of capital investments and operating costs through rates in Texas and New Mexico
- Uncertainties and instability in the general economy and the resulting impact on EE's sales and profitability
- Unanticipated increased costs associated with scheduled and unscheduled outages
- The size of our construction program and our ability to complete construction on budget and on time
- The costs at Palo Verde
- Deregulation and competition in the electric-utility industry
- Possible increased costs of compliance with environmental or other laws, regulations and policies
- Possible income tax and interest payments as a result of audit adjustments proposed by the IRS
- Uncertainties and instability in the financial markets and the resulting impact on EE's ability to access the capital and credit markets
- Other factors detailed by EE in its public filings with the Securities and Exchange Commission. Please refer to EE's 2010 Form 10-K and other 1934 Act filings

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, 2010

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 001-14206

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 whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
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. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 126-2 of the Exchange Act.

Large accelerated filer _X_ Accelerated filer _____ Non-accelerated filer _____
(Do not check if a smaller reporting company) 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, 2010, the aggregate market value of the voting stock held by non-affiliates of the registrant was $831,710,988 (based on the closing price as quoted on the New York Stock Exchange on that date).

As of January 31, 2011, there were 42,627,451 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 2011 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
2009 New Mexico Stipulation	Stipulation in Case No. 09-00171-UT dated October 8, 2009, 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
ASU	Accounting Standards Updates
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 Artillery Center & Fort Bliss next to 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
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
PUCT	Public Utility Commission of Texas
RGEC	Rio Grande Electric Cooperative
RGRT	Rio Grande Resources Trust II
SPS	Southwestern Public Service Company
TEP	Tucson Electric Power Company
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,
- ratemaking/regulatory matters,
- 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 ability to recover our costs and earn a reasonable rate of return on our invested capital through rates,
- ability of our operating partners to maintain plant operations and manage operation and maintenance costs at the Palo Verde and Four Corners plants,
- reductions in output at generation plants operated by the Company,
- unscheduled outages, including outages at Palo Verde,
- the size of our construction program and our ability to complete construction on budget and on a timely basis,
- 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 and the impact of severe weather conditions,
- rates, cost recoveries and other regulatory matters including the ability to recover fuel costs on a timely basis,
- changes in environmental regulations, including those related to air, water or greenhouse gas emissions or other environmental matters,
- 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 and other postretirement plan assets,
- the impact of the U.S. health care reform legislation,
- the impact of changing cost escalation and other assumptions on our nuclear decommissioning liability for Palo Verde,
- Texas, New Mexico and electric industry utility service reliability standards,
- homeland security considerations including those associated with the U.S./Mexico border region,
- 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 full requirements wholesale customer in Texas. The Company owns or has significant ownership interests in six electrical generating facilities providing it with a net dependable generating capability of approximately 1,643 MW. For the year ended December 31, 2010, the Company's energy sources consisted of approximately 45% nuclear fuel, 27% natural gas, 6% coal, 22% purchased power and less than 1% generated by wind turbines.

The Company serves approximately 377,000 residential, commercial, industrial, public authority and wholesale customers. The Company distributes electricity to retail customers principally in El Paso, Texas and Las Cruces, New Mexico (representing approximately 64% and 11%, respectively, of the Company's retail revenues for the year ended December 31, 2010). In addition, the Company's wholesale sales include sales for resale to other electric utilities and power marketers. Principal industrial, public authority and other large retail 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, oil refining, two large universities, steel production and copper refining 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, 2011, the Company had approximately 1,000 employees, 41% 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

As of December 31, 2010, the Company's net dependable generating capability of 1,643 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	614
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		1,643

Palo Verde Station

The Company owns a 15.8% interest, or approximately 633 MW, in the three nuclear generating units and common facilities ("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.

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.

The NRC has granted facility operating licenses and full power operating licenses for Palo Verde Units 1, 2 and 3, which expire in 2025, 2026 and 2027, respectively. In addition, the Company is separately licensed by the NRC to own its proportionate share of Palo Verde. In December 2008, APS, as agent for the Palo Verde Participants, filed an application with the NRC to extend the Palo Verde licenses for 20 years. In January 2011, APS received notice that the NRC had issued a final safety evaluation report which concluded that the application met the standards for issuance of a 20-year license renewal. The NRC also issued its final supplemental environmental impact statement which concluded that there are no environmental impacts that would preclude license renewal for an additional 20 years. These two reports document the NRC staff's review and conclusions regarding the Palo Verde license renewal application. The final decision on the Palo Verde license renewal application will be made by the NRC's director of Nuclear Reactor Regulation and is expected in April 2011.

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 enables the Company to record a current deduction for federal income tax purposes for most of the amounts funded. At December 31, 2010, the Company's decommissioning trust fund had a balance of $153.9 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. On March 26, 2008, the Palo Verde Participants approved the 2007 Palo Verde decommissioning study (the "2007 Study"). The 2007 Study estimated that the Company must fund approximately $324.4 million (stated in 2007 dollars) to cover its share of decommissioning costs which was a reduction in decommissioning costs from the 2004 Palo Verde decommissioning study and will result in lower asset retirement obligations and lower expenses in the future. Although the 2007 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 commissioned in 2010 ("2010 Study"). The final application of the 2010 Study is pending the NRC's decision to approve the application to extend the Palo Verde licenses for 20 years as discussed above. 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 on-site facilities until accepted by the DOE for permanent disposal. The 2007 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 current 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. In November 1997, the United States Court of Appeals for the District of Columbia Circuit issued a decision preventing the DOE from excusing its own delay but refused to order the DOE to begin accepting spent nuclear fuel. The Company cannot predict when spent fuel shipments to the DOE 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. APS pursued a damages claim for costs incurred through December 2006 in a trial that began on January 28, 2009. On June 18, 2010, the court awarded APS and the other Palo Verde Participants approximately $30 million. In October 2010, the Company received $4.8 million, representing its share of the award. The majority of the award was refunded to customers through the applicable fuel adjustment clauses. APS is continuing to pursue settlement of damage claims for costs incurred after 2006.

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. The construction and opening of low-level radioactive waste disposal sites have been delayed due to extensive public hearings, disputes over environmental issues and review of technical issues related to the proposed sites. The opposition, delays, uncertainty and costs that have been experienced 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.

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 $12.6 billion. This potential liability is covered by primary liability insurance provided by commercial insurance carriers in the amount of $375 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 $117.5 million, subject to an annual limit of $17.5 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 $55.7 million, with an annual payment limitation of approximately $8.3 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 $8.95 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 two combined cycle generating units, including a 288 MW combined cycle generating unit designated as Newman Unit 5. Construction of Newman Unit 5 began in July 2008 and will be completed in two phases. The first phase, consisting of two 70 MW gas turbine generators, was completed in May 2009. The second phase will add two heat recovery steam generators and a steam turbine with an expected net capability of 148 MW and is currently expected to be completed before the summer of 2011. The current aggregate net capability of the Newman Power Station is approximately 614 MW. After completion of the second phase of Newman Unit 5, the total aggregate net capacity will be 762 MW. The station operates 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 on natural gas.

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.

APS, on behalf of the Four Corners participants, has negotiated amendments to the existing facility lease with the Navajo Nation which would extend the Four Corners leasehold interest to 2041. Execution by the Navajo Nation of the lease amendments is a condition to closing of a purchase by APS of SCE's interests in Four Corners. The execution of these amendments by the Navajo Nation requires the approval of the Navajo Nation Council, which occurred on February 15, 2011 and is awaiting final signature by the Nation's President. The effectiveness of the amendments also requires the approval of the Department of the Interior ("DOI"), as does a related Federal rights-of-way grant which the Four Corners participants will pursue. A Federal environmental review will be conducted as part of the DOI review process.

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 on natural gas.

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 10%, is used as net capability for resource planning purposes.

Transmission and Distribution Lines and Agreements

The Company owns or has significant ownership interests in four 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 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 Company's Arroyo Substation located near Las Cruces, New Mexico. West Mesa Substation is the primary delivery point for the Company's generation entitlement from Four Corners, which is transmitted from Four Corners 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 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 also 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. The Company also owns 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 owns 14.86% and 9.35% respectively 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

General. The Company is subject to laws and regulations with respect to air, soil and water quality, waste disposal and other environmental matters by federal, state, regional, tribal and local authorities. Those authorities govern 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 or other sanctions. In addition, releases of pollutants or contaminants into the environment can result in costly cleanup obligations. 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. Certain key environmental issues, laws and regulations facing the Company are described further below.

Air Emissions. The U.S. Clean Air Act ("CAA") and comparable state laws and regulations relating to air emissions impose, among other obligations, limitations on pollutants generated during the Company's operations, including sulfur dioxide ("SO2"), particulate matter, nitrogen oxides ("NOx") and mercury.

Clean Air Interstate Rule. The U.S. Environmental Protection Agency's ("EPA") Clean Air Interstate Rule ("CAIR") as applied to the Company, involves requirements to limit emissions of NOx from the Company's power plants in Texas and/or purchase allowances representing other parties' emissions reductions starting in 2009. Although the U.S. Court of Appeals for the District of Columbia voided CAIR in 2008, the Company must comply with CAIR until the EPA rewrites the rule as required by the Court's final opinion. The 2010 reconciliation to comply with CAIR is due March 2011 and the Company purchased and expensed $0.3 million of allowances during 2010 to meet its estimated requirement.

Clean Air Transport Rule. In July 2010, the EPA proposed as a replacement to CAIR, the Clean Air Transport Rule ("CATR"). CATR would require 31 states, including Texas, and the District of Columbia to issue regulations and develop a scheme by which power plants in their respective jurisdictions will further reduce emissions of SO2 and NOx. Reductions would be required beginning in 2012, with further reductions likely to be required in 2014. The EPA expects CATR to be finalized in July 2011, but it is unclear when the states would issue implementing regulations. There are a number of other uncertainties relating to this proposed rule, including whether it will be ultimately finalized and how the states will implement the requirements. As a result, the ultimate impact of this rule on the Company's operations cannot currently be determined, but it could be material.

Ozone. NOx emissions can lead to the formation of ozone. Ozone levels are limited by the National Ambient Air Quality Standards established by the EPA. The EPA is in the process of revising these standards. If these revisions result in more stringent standards, the Company could be required to place additional NOx pollution control measures on certain of its generating facilities. Without knowing the new ozone standards, the ultimate impact on the Company's facilities cannot be determined. However the impact of these regulations and associated costs could be material.

Climate Change. A significant portion of the Company's generation assets are nuclear or gas-fired, and as a result, the Company believes that its greenhouse gas ("GHG") emissions are low relative to electric power companies who rely on more coal-fired generation. However, regulations governing the emission of GHGs, such as carbon dioxide, could impose significant costs or limitations on the Company. In recent years, the U.S. Congress has considered new legislation to restrict or regulate GHG emissions, although federal efforts directed at enacting comprehensive climate change legislation stalled in 2010 and appear highly unlikely to recommence in 2011. Nonetheless, it is possible that federal legislation related to GHG emissions will be considered in Congress in the future. The EPA has also proposed using the CAA to limit carbon dioxide and other GHG emissions, and GHG emissions regulations have been adopted by EPA in recent years, with additional regulations proposed or in development.

Significant GHG emissions regulations have been adopted by EPA in recent years with additional regulations proposed or in development. In September 2009, the EPA adopted a rule requiring approximately 10,000 facilities comprising a substantial percentage of annual U.S. GHG emissions to inventory their emissions starting in 2010 and to report those emissions to the EPA beginning in 2011. The Company's fossil fuel-fired power generating assets are subject to this rule. The Company also has inventoried and implemented procedures for electrical equipment containing sodium hexafluoride (SF6), another GHG. The Company is tracking these GHG emissions pursuant to EPA's new SF6 reporting rule that was finalized in late 2010 and became effective January 1, 2011. The first report to EPA under this rule is due March 31, 2012.

EPA has also proposed and finalized other rulemakings on GHG emissions that affect electric utilities. Under EPA regulations finalized in May 2010 (referred to as the "Tailoring Rule"), the EPA began regulating GHG emissions from certain stationary sources in January 2011. The regulations are being implemented pursuant to two CAA programs: the Title V Operating Permit program and the program requiring a permit if undergoing construction or major modifications (referred to as the "PSD" program). Obligations relating to Title V permits will include recordkeeping and monitoring requirements. With respect to PSD permits, projects that cause a significant increase in GHG emissions (currently defined to be more than 75,000 tons or more per year or 100,000 tons or more per year, depending on various factors), will be required to implement "best available control technology", or "BACT". The EPA has issued guidance on what BACT entails for the control of GHGs and individual states are now required to determine what controls are required for facilities within their jurisdiction on a case-by-case basis. The ultimate impact of these new regulations on the Company's operations cannot be determined at this time, but the cost of compliance with new regulations could be material. Also, on December 23, 2010, EPA announced a settlement agreement with states and environmental groups regarding setting new source performance standards for GHG emissions from new and existing coal-, gas- and oil-based power plants. Pursuant to this agreement, EPA will propose standards for both new or modified boilers and for existing facilities by July 26, 2011, and finalize those standards by May 26, 2012. The impact of these rules on the Company is unknown at this time, but they could result in material costs.

In addition, almost half of the states, either individually or through multi state regional initiatives, have begun to consider how to address GHG emissions and are actively considering the development of emission inventories or regional GHG cap and trade programs. 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 Climate Initiative and is pursuing initiatives to reduce GHG emissions in the state. The New Mexico Environmental Improvement Board approved two separate rulemakings in November and December 2010 to limit GHG emissions from certain stationary sources. Under the November 2010 regulation, stationary sources that emit 25,000 metric tons or more of carbon dioxide a year would be required to reduce their GHG emissions by 2% per year from 2012 through 2020. The December 2010 regulation establishes a cap-and-trade system which would require certain industrial and electric generating facilities with carbon dioxide emissions in excess of 25,000 metric tons per year to reduce their emissions by 3% per year below 2010 levels. There are various uncertainties relating to these regulations, including whether current legal challenges to them will be successful, but as drafted, the Company does not expect these regulations to result in significant costs to the Company.

It is not currently possible to predict with confidence how any pending, proposed or future GHG legislation by Congress, the states, or multi-state regions or regulations adopted by EPA or the state environmental agencies will impact our business. However, any such legislation or regulation of GHG emissions or any future related litigation could result in increased compliance costs or additional operating restrictions or reduced demand for the power the Company generates, could require the Company to purchase rights to emit GHG, and could have a material adverse effect on the Company's business, financial condition, reputation or results of operations.

Climate change also has potential physical effects that could be relevant to the Company's business. In particular, some studies suggest that climate change could affect the Company's service area by causing higher temperatures, less winter precipitation and less spring runoff, as well as by causing more extreme weather events. Such developments could change the demand for power in the region and could also impact the price or ready availability of water supplies or affect maintenance needs and the reliability of Company equipment.

The Company believes that material effects on the Company's business or operations may result from the physical consequences of climate change, the regulatory approach to climate change ultimately selected and implemented by governmental authorities, or both. 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. Given the very significant remaining uncertainties regarding whether and how these issues will be regulated, as well as the timing and severity of any physical effects of climate change, the Company believes it is impossible at present to meaningfully quantify the costs of these potential impacts.

Contamination Matters. The Company has a provision for environmental remediation obligations of approximately \$0.4 million at December 31, 2010, 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 EPA has investigated releases or potential releases of hazardous substances, pollutants or contaminants at the Gila River Boundary Site, on the Gila River Indian Community ("GRIC") reservation in Arizona and designated it as a Superfund site. The Company currently owns 16.29% of the site and will share in the cost of cleanup of this site. The Company has a tentative agreement with the former property owner and in 2011, the Company is expected to enter into a consent decree with the EPA at a cost to the Company of less than \$0.1 million (which amount is included in the \$0.4 million accrued at December 31, 2010).

In 2006, the Company experienced an oil discharge at the Rio Grande Power Station. The Company remediated the site by removing the contaminated soil and installing monitoring wells to monitor for the presence of hydrocarbons in the ground water. The Company's abatement plan was approved by the New Mexico Environment Department, and the Company further assessed and remediated the site in accordance with the plan in 2010. The Company has incurred \$0.3 million in costs related to this matter. Although monitoring of the groundwater continues in accordance with the NMED-approved abatement plan, the Company does not expect any significant additional costs to be incurred related to the 2006 discharge.

Environmental Litigation and Investigations. In May 2007, the EPA finalized a new federal implementation plan that addresses air emissions at Four Corners. APS, the Four Corners operating agent, has filed suit against the EPA relating to this new federal implementation plan to resolve issues involving operating flexibility for emission opacity standards. The Company cannot predict the outcome of the suit filed against the EPA or whether compliance with the implementation plan, as currently drafted or as amended, could have an adverse effect on its capital or operating costs.

On April 6, 2009, APS received a request from the EPA under Section 114 of the CAA seeking detailed information regarding projects and operations at Four Corners. APS has responded to this request. The Company is unable to predict the timing or content of EPA's response or any resulting actions.

On February 16, 2010, a group of environmental organizations filed a petition with the United States Departments of Interior and Agriculture requesting that the agencies certify to the EPA that emissions from Four Corners are causing "reasonably attributable visibility impairment" under the CAA. APS is currently reviewing the petition and has indicated that it will likely file a response in opposition to the petition. The Company cannot predict the outcome of the petition or whether any resulting actions could have an adverse effect on its capital or operating costs.

Construction Program

Utility construction expenditures reflected in the following table consist primarily of additions to local generation, new generation capacity, expanding and updating the transmission and distribution systems, and 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 and to replace retiring plants and terminated purchased power agreements, the costs of which are included in the table below. Certain of the estimated cash construction costs are subject to regulatory input and approval. Additional renewable energy projects could be added to the construction program and other modifications of the construction program could occur based on potential agreements with regulatory authorities.

The Company's estimated cash construction costs for 2011 through 2014 are approximately $834 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)	
2011	$ 208
2012	227
2013	179
2014	220
Total	$ 834

By Function (In millions)	
Production (1)(2)	$ 474
Transmission	60
Distribution	228
General	72
Total	$ 834

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

(2) $289 million has been allocated for new generating capacity including $19 million to complete Newman Unit 5, $73 million for an 87 MW peaking unit at the Rio Grande Station, $174 million to start the next 290 MW combined cycle unit which would come on line in 2016, $11 million for anticipated renewable projects to be built in El Paso and $12 million for other generation expansion projects. Total Production expenditures also include $16 million for improvements in local generation, $31 million for Four Corners and $138 million for Palo Verde.

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, 2010	2009	2008
Nuclear	45%	45%	42%
Natural gas	27	22	24
Coal	6	7	6
Purchased power	22	26	28
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 PUCT 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 or are currently negotiating contracts that when combined with the current inventory will furnish 100% of Palo Verde's operational requirements for uranium concentrates, conversion and enrichment services through 2018. In addition, the Palo Verde Participants have contracted 100% of fabrication services until at least 2016 for each Palo Verde unit.

Pursuant to the ANPP Participation Agreement, the Company owns an undivided interest in nuclear fuel purchased in connection with Palo Verde. The Palo Verde Participants have sought to mitigate the effects of potential supply disruptions and price increases by employing a procurement strategy where (i) nuclear fuel arrives on site up to three months before being loaded and (ii) an inventory of converted nuclear fuel material sufficient to provide feed stock for one full reactor reload is stored for future use.

Nuclear Fuel Financing. The Company's financing of nuclear fuel is accomplished through Rio Grande Resources Trust ("RGRT"), a Texas grantor trust, which is consolidated in the Company's financial statements. On August 17, 2010, RGRT completed the sale of $110 million aggregate principal amount of senior notes. The Company guarantees RGRT's payment of principal and interest on the senior notes. The proceeds from the sale of the senior notes were used by RGRT to repay amounts borrowed under the then existing revolving credit facility and enable future nuclear fuel financing requirements of RGRT to be met with a combination of the senior notes and amounts borrowed under the revolving credit facility.

On September 23, 2010, the Company, along with RGRT, entered into a new credit agreement for a $200 million revolving credit facility (the "RCF"). The RCF has a term of four years, and the Company may request that the facility be increased up to $300 million during the term of the facility, subject to lender approval. Any amounts borrowed by RGRT may be used to finance the acquisition and processing of nuclear fuel. This RCF replaces the $200 million revolving credit facility that was due to expire on April 11, 2011. The total amount borrowed for nuclear fuel by RGRT at December 31, 2010 was $114.7 million of which $4.7 million had been borrowed under this new RCF, and $110 million was borrowed through the senior notes discussed above. Interest costs on borrowings to finance nuclear fuel are accumulated by RGRT and charged to the Company as fuel is consumed and recovered from customers through fuel recovery charges.

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 2010, 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 2011. 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 Stations. 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 became effective October 1, 2009 and continues through 2017. The intrastate natural gas agreement was amended effective September 1, 2010.

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. In June 2010, the Four Corners coal contract was renegotiated with the coal supplier, resulting in reduced coal prices for the remaining term of the agreement. The new Four Corners coal contract expires in mid-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 through mid-2016.

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.

The Company initiated a Power Purchase and Sale Agreement with Freeport-McMoran Copper and Gold Energy Services LLC ("Freeport") formerly Phelps Dodge Energy Services LLC in June 2006. The contract provides for Freeport to deliver energy to the Company from its ownership interest in the Luna Energy Facility (a 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 Greenlee, Arizona. The Company may purchase up to 100 MW at a specified price at times when energy is not exchanged under the Power Purchase and Sale Agreement. Upon mutual agreement, the contract allows the parties to increase the amount of energy that is purchased and sold under the Power Purchase and Sale Agreement. The parties agreed to increase the amount to 125 MW from December 2008 through December 2011. The contract was approved by the FERC and continues through December 31, 2021.

The Company entered into an agreement in 2009 to purchase capacity of up to 40 MW and unit contingent energy during 2010 from Shell Energy North America ("Shell"). Under the agreement, the Company provides natural gas to Pyramid Unit No. 4 where Shell has the right to convert natural gas to electric energy. The Company entered into a contract with Shell on May 17, 2010 to extend the term of the capacity and unit contingent energy purchase from January 1, 2011 through September 30, 2014.

The Company entered into a 20-year contract with New Mexico SunTower, LLC ("NM SunTower") in 2008 for the purchase of the output of a 92-MW concentrated solar plant which was expected to begin commercial operation in 2011. NM SunTower is an affiliate of NRG Energy, Inc. NM SunTower failed to meet its financial commitment milestone, and, on May 3, 2010, the Company delivered to NM SunTower a notice of default as provided under the terms of the contract. The Company presented testimony to the NMPRC at a hearing June 8, 2010, seeking approval for NM SunTower's request to revise the contract to (i) change the technology from concentrated solar to photovoltaic, (ii) downsize the solar project from 92 MW to 20 MW, and (iii) delay the date for commercial operation to December 31, 2011, at the earliest. The Company also requested deferral of its 2011 solar diversity requirements to the 2012-2014 period and approval to meet its 2011 RPS with purchases of renewable energy credits ("RECs") from a third party. On June 24, 2010, the NMPRC approved changes to the contract with NM SunTower. (See "Regulation – New Mexico Regulatory Matters.")

On July 1, 2010, the Company made its annual Plan filing requesting approval for 25-year purchase power agreements for two additional solar photovoltaic projects totaling 24 MW, consisting of two 12 MW projects located in southern New Mexico with the first expected to be operational by December 31, 2011. The second 12 MW project is expected to be operational by June 30, 2012. The Company also requested approval for a 25-year purchase power agreement for a 5 MW photovoltaic project also located in southern New Mexico expected to be operational by June 30, 2011. In addition, approval for the purchase of RECs to meet the Company's RPS requirements for the 2011 to 2014 period was requested. The NMPRC approved the contracts and the Company's request to purchase RECs to meet RPS requirements in its Final Order issued December 16, 2010.

Other purchases of shorter duration were made during 2010 to replace the Company's generation resources during planned and unplanned outages and for economic reasons as well as to supply off-system sales.

Operating Statistics

	Years Ended December 31,		
	2010	2009	2008
Operating revenues (in thousands):			
Non-fuel base revenues:			
Retail:			
Residential	$ 217,615	$ 195,798	$ 184,800
Commercial and industrial, small	188,390	175,328	174,593
Commercial and industrial, large	43,844	34,804	36,318
Sales to public authorities	86,460	77,370	74,427
Total retail base revenues	536,309	483,300	470,138
Wholesale:			
Sales for resale	1,943	2,037	1,646
Total non-fuel base revenues	538,252	485,337	471,784
Fuel revenues:			
Recovered from customers during the period	170,588	196,081	198,292
Under (over) collection of fuel	(35,408)	(66,608)	42,752
New Mexico fuel in base rates	71,876	69,026	68,631
Total fuel revenues	207,056	198,499	309,675
Off-system sales	105,317	116,064	232,500
Other	26,626	28,096	24,971
Total operating revenues	$ 877,251	$ 827,996	$1,038,930
Number of customers (end of year):			
Residential	334,729	328,553	322,618
Commercial and industrial, small	37,202	36,306	35,850
Commercial and industrial, large	50	48	49
Other	4,841	4,964	4,935
Total	376,822	369,871	363,452
Average annual kWh use per residential customer	7,560	7,244	6,955
Energy supplied, net, kWh (in thousands):			
Generated	8,465,659	7,979,290	8,023,475
Purchased and interchanged	2,420,869	2,745,500	3,152,396
Total	10,886,528	10,724,790	11,175,871
Energy sales, kWh (in thousands):			
Retail:			
Residential	2,508,834	2,361,650	2,227,838
Commercial and industrial, small	2,295,537	2,251,399	2,255,585
Commercial and industrial, large	1,087,413	1,024,186	1,102,277
Sales to public authorities	1,542,389	1,482,448	1,448,654
Total retail	7,434,173	7,119,683	7,034,354
Wholesale:			
Sales for resale	53,637	56,931	50,148
Off-system sales	2,822,732	2,995,984	3,506,770
Total wholesale	2,876,369	3,052,915	3,556,918
Total energy sales	10,310,542	10,172,598	10,591,272
Losses and Company use	575,986	552,192	584,599
Total	10,886,528	10,724,790	11,175,871
Native system:			
Peak load, kW	1,616,000	1,571,000	1,524,000
Net dependable generating capability for peak, kW (1)	1,643,000	1,643,000	1,503,000
Total system:			
Peak load, kW (2)	1,889,000	1,723,000	1,669,000
Net dependable generating capability for peak, kW (1) (3)	1,643,000	1,643,000	1,503,000

(1) 2010 and 2009 include a 140,000 kW increase in generating capability at Newman related to the completion of the first phase of the Newman Unit 5 construction which consists of two 70,000 kW gas turbine generators.
(2) Includes spot firm sales and net losses of 273,000 kW, 152,000 kW and 145,000 kW for 2010, 2009 and 2008, respectively.
(3) Excludes 100,000 kW, 233,000 kW and 333,000 kW for 2010, 2009 and 2008, respectively, of firm on-peak purchases.

Regulation

General

The rates and services of the Company are regulated by incorporated municipalities in Texas, the PUCT, the NMPRC, and the FERC. The PUCT 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 and compliance with federally-mandated reliability standards. The decisions of the PUCT, NMPRC and the FERC are subject to judicial review.

Texas Regulatory Matters

Texas Freeze Period. In 2005, the Company entered into agreements ("Texas Rate Agreements") with El Paso, PUCT staff and other parties in Texas that provided for most retail base rates to remain at their existing level through June 30, 2010. During the rate freeze period, if the Company's return on equity fell below the bottom of a defined range, the Company had the right to initiate a rate case and seek an adjustment to base rates. If the Company's return on equity exceeded the top of the range, the Company would refund an amount equal to 50% of the Texas jurisdictional pretax return in excess of the ceiling. The Company's return on equity fell within the then prevailing range during the last reporting period. Also pursuant to the Texas Rate Agreements, the Company agreed to share with its Texas customers 25% of off-system sales margins increasing to 90% after June 30, 2010.

2009 Texas Retail Rate Case. On December 9, 2009, the Company filed an application with the PUCT for authority to change rates, to reconcile fuel costs, to establish formula-based fuel factors, and to establish an energy efficiency cost-recovery factor. This case was assigned PUCT Docket No. 37690. The filing included a base rate increase which was based upon an adjusted test year ended June 30, 2009.

On July 30, 2010, the PUCT approved a settlement in the 2009 Texas retail rate case in PUCT Docket No. 37690. The settlement calls for an annual non-fuel base rate increase of $17.15 million effective for usage beginning July 1, 2010. This increase was partially offset by the provision that, consistent with a prior rate agreement, effective July 1, 2010, the Company shares 90% of off-system sales margins with customers and retains 10% of such margins. Previously, the Company retained 75% of off-system sales margins. Interim rates went into effect July 1, 2010 pending final approval by the PUCT. All additions to electric plant in service since June 30, 1993 through June 30, 2009 were deemed to be reasonable and necessary with the exception of one small addition. The Company's new customer information system completed in April 2010 was also included in base rates with a ten-year amortization. The settlement provides for the reconciliation of fuel costs incurred through June 30, 2009 except for the recovery of final Four Corners' coal mine reclamation costs. The fuel reconciliation (Docket No. 38361) was bifurcated from the rate case to allow for litigation of the final coal mine reclamation costs. The PUCT also approved the use of a formula-based fuel factor which provides for more timely recovery of fuel costs. The PUCT approved a $19.7 million or 11% reduction in the Company's fixed fuel factor as the initial rate under the approved fuel factor formula. The PUCT also approved an energy efficiency cost-recovery factor that includes the recovery of deferred energy efficiency costs over a three-year period.

Fuel Reconciliation Case (Severed from 2009 Rate Case). Pursuant to the stipulation in Docket No. 37690, the fuel reconciliation component of the rate case was severed and a separate docket, PUCT Docket No. 38361, was established to address one fuel reconciliation issue not settled by the parties. That single issue was a determination of the proper amount of the Four Corners' coal mine final reclamation costs to be recovered from the Company's Texas retail customers. The hearing on the merits of the case was held on August 11, 2010. On November 23, 2010 the Administrative Law Judge issued the Proposal for Decision which approved the Company's request. The PUCT issued a final order approving the Proposal for Decision on January 27, 2011.

Fuel and Purchased Power Costs. The Company's actual fuel costs, including purchased power energy costs, are recoverable from its customers. The PUCT has adopted a fuel cost recovery rule ("Texas Fuel Rule") that allows the Company to seek periodic adjustments to its fixed fuel factor. The Company received approval on July 30, 2010 in PUCT Docket No. 37690 (discussed above), to implement a formula to determine its fuel factor. The Company can seek to revise its fixed fuel factor based upon the approved formula at least four months after its last revision except in the month of December. The Texas Fuel Rule requires the Company to request to refund fuel costs in any month when the over-recovery balance exceeds a threshold material amount and it expects fuel costs to continue to be materially over-recovered. The Texas Fuel Rule also permits the Company to seek to surcharge fuel under-recoveries in any month the balance exceeds a threshold material amount and it expects fuel cost recovery to continue to be materially under-recovered. Fuel over and under recoveries are considered material when they exceed 4% of the previous twelve months' fuel costs. All such fuel revenue and expense activities are subject to periodic final review by the PUCT in fuel reconciliation proceedings.

On December 17, 2009, the Company filed a petition with the PUCT in Docket No. 37788 to refund $11.8 million in fuel cost over-recoveries, including interest, for the period September through November 2009. On January 20, 2010, a stipulation was filed that resolved all of the issues in this proceeding. The stipulation provided for the Company to implement a fuel refund for the net over-recovery of $11.8 million, including interest, in the month of February 2010. On January 21, 2010, the Administrative Law Judge assigned to the docket issued an order approving the implementation of interim rates to allow the requested refund to be made. The PUCT issued a final order on February 11, 2010 approving the stipulation.

On November 23, 2010, the Company filed a Petition to Revise its Fixed Fuel Factor pursuant to the Fuel Factor Formula authorized in PUCT Docket No. 37690 for determining the Company's fuel factor. The Company's request was to decrease its fixed fuel factor by 14.7%. On December 2, 2010, the State Office of Administrative Hearings ("SOAH") Administrative Law Judge issued Order No. 1, establishing interim rates as requested, as well as a deadline of December 3, 2010, for the purpose of requesting a hearing, and absent such a request, implementation of the revised fuel factor would become final by its own terms and without further PUCT order. No request was received; therefore, the revised fuel factor became final. On January 6, 2011, the SOAH Administrative Law Judge dismissed the proceeding from the SOAH docket, the case was dismissed from the PUCT's docket on that same date, and the case was closed.

On October 20, 2010, the Company filed a petition with the PUCT which was assigned Docket No. 38802 to refund $12.8 million in fuel cost over-recoveries, including interest, for the period April 2010 through September 2010. In its filing, the Company requested the refund be made to customers in the single billing month of December 2010. On November 22, 2010, a stipulation was filed that resolved all issues in this case and requested that an order be issued that would allow the interim refund in December 2010 consistent with the Company's filing. The Administrative Law Judge issued an order approving the implementation of interim rates to allow the requested refund to be made in December. On December 16, 2010, the PUCT issued a final order approving the stipulation.

On May 12, 2010, the Company filed a petition with the PUCT which was assigned Docket No. 38253 to refund $10.5 million in fuel cost over-recoveries, including interest, for the period December 2009 through March 2010. On June 14, 2010, the Company and all other parties filed a stipulation that resolved all of the issues in this case. In the stipulation, the Company and the other parties agreed to increase the refund by $0.6 million to remove costs for the purchase of renewable energy credits from the Company's fuel cost, and as a result of that adjustment and the associated recalculation of interest, the total refund was $11.1 million. On June 16, 2010, the Administrative Law Judge assigned to the docket issued an order approving the implementation of interim rates to allow the requested refund to be made in July and August 2010. The PUCT issued a final order on July 15, 2010 approving the stipulation.

On February 18, 2011, the Company filed a petition with the PUCT which was assigned Docket No. 39159 to refund $11.8 million in fuel cost over-recoveries, including interest, for the period October 2010 through December 2010. In its filing, the Company requested the refund be made to customers in the single billing month of April 2011. This case is pending.

Application for Approval to Revise Energy Efficiency Cost Recovery Factor for 2011. On June 1, 2010, the Company filed with the PUCT an application for approval to revise its energy efficiency cost recovery factor ("EECRF"), which was assigned PUCT Docket No. 38226. The Company requested that its revised EECRF become effective beginning with the first billing cycle of its January 2011 billing month. In its application, the Company requested authority to increase its 2011 EECRF to a total of $6.6 million to recover $4.2 million in energy efficiency costs projected to be incurred in 2011, a performance bonus of $0.1 million for the Company's 2009 program performance, and $2.3 million in annual amortization of the energy efficiency costs that were deferred pursuant to the PUCT's final order in Docket No. 35612. A final order approving the Company's application was issued on October 4, 2010.

Application for a Certificate of Convenience and Necessity for Rio Grande Unit 9. On September 30, 2010, the Company filed a petition seeking a Certificate of Convenience and Necessity to construct an 87 MW natural gas-fired combustion turbine unit at the Company's existing Rio Grande Generating Station in the City of Sunland Park in southeast New Mexico. This case was assigned PUCT Docket No. 38717. An intervention deadline of November 15, 2010 was established and the PUCT issued a Preliminary Order in this case on January 26, 2011. The procedural schedule has been suspended while the parties negotiate a settlement.

New Mexico Regulatory Matters

2009 New Mexico Stipulation. On May 29, 2009, the Company filed a general rate case using a test year ended December 31, 2008. The 2009 rate case was docketed as NMPRC Case No. 09-00171-UT. A comprehensive unopposed stipulation (the "2009 New Mexico Stipulation") was reached in this general rate case and filed on October 8, 2009. The 2009 New Mexico Stipulation provided for an increase in New Mexico jurisdictional non-fuel and purchased power base rate revenues of $5.5 million. The 2009 New Mexico Stipulation provided for the revision of depreciation rates for the Palo Verde nuclear generating plant to reflect a 20-year life extension and a revision of depreciation rates for other plant in service. The 2009 New Mexico Stipulation also provided for the continuation of the Company's Fuel and Purchased Power Cost Adjustment Clause ("FPPCAC") without conditions or variance. In addition, it modified the market pricing of capacity and energy provided by Palo Verde Unit 3 using a methodology based upon a previous purchased power contract with Credit Suisse Energy, LLC. On December 10, 2009, the NMPRC issued a final order conditionally approving and clarifying the unopposed stipulation, and the stipulated rates went into effect with January 2010 bills.

Investigation into Recovering County Franchise Fees. On December 10, 2009, the NMPRC issued an order in NMPRC Case No. 09-00421-UT, requiring the Company to show cause why it should collect franchise fees from its customers on behalf of Doña Ana and Otero Counties (the "Counties"). The Company responded to the order on January 5, 2010. On January 26, 2010, the NMPRC issued a final order concluding that the imposition of franchise fees by New Mexico counties is not authorized under New Mexico law and, therefore, the Company may not pass through to its customers some past and all ongoing franchise fees imposed by the Counties. The order concluded that only "home rule" municipalities, who had adopted a charter under the state constitution, could impose franchise fees or taxes, provided the residents so voted.

As a result of its findings, the NMPRC directed the Company to immediately cease passing through to its customers any franchise fees paid by the Company to the Counties. The NMPRC also directed the Company to refund to its customers in the Counties the amount of franchise fees charged to those customers since June 1, 2004, plus interest. The order stated that the Company was required to refund these franchise fees to customers over a three-year period through a credit on customer bills.

The Company filed a Notice of Appeal with the New Mexico Supreme Court on January 27, 2010 (the "Appeal"), seeking to set aside the order on legal and jurisdictional grounds. The Company followed with a motion for Emergency Stay on January 29, 2010, asking the New Mexico Supreme Court to stay the order pending the Appeal. The Company also asked the NMPRC, on February 12, 2010, to delay implementation of its order pending the Appeal. The Counties moved to intervene in the Appeal on February 10, 2010. The Company had placed pending franchise payments to the Counties in separate accounts pending resolution of the proceedings. However, beginning in April 2010 the Company began paying franchise payments to the Counties in accordance with the current franchise agreements. On February 22, 2010, the New Mexico Supreme Court granted the Company's motion for Emergency Stay pending the outcome of the Appeal and granted the Counties' motion to intervene in the Appeal. In February 2010, the New Mexico legislature passed legislation that confirmed the legality of the Company's existing franchise agreements with the Counties. On October 26, 2010, the New Mexico Supreme Court issued its opinion and held that the franchise fee charges fall outside the NMPRC's jurisdiction and vacated and annulled the NMPRC's order.

Investigation into the Service Quality of the Company. On October 22, 2009, NMPRC Staff filed a petition requesting an investigation into the quality of service of the Company's power distribution system in the Santa Teresa Industrial Park, based upon a report prepared for customers in that area by the Los Alamos National Laboratory. On October 27, 2009, the NMPRC decided to initiate an investigation and ordered the Company to respond no later than November 16, 2009. The Company filed an initial response on November 16, 2009 and a supplemental response on January 8, 2010 after obtaining data on which the report was based. The Company responses provided evidence that the reliability and power quality performance for the Company's service territory as a whole and on the Santa Teresa circuits in particular meet all applicable reliability standards and comport with good utility practices. On January 28, 2010, the NMPRC Staff filed a reply stating that it found no factual basis to conclude that the Company had violated NMPRC rules and recommended the NMPRC dismiss this proceeding.

On June 8, 2010, the hearing examiner issued a recommended decision concluding that there is no substantial evidence that would support the allegations in this case regarding the Company's quality of service. The hearing examiner found there is good cause to dismiss the investigation and close the docket without further proceedings. On November 4, 2010, the NMPRC issued a final order approving the recommended decision.

2010 Energy Efficiency Program Approval. On January 19, 2010, the Company filed its Application for Approval of its 2010 Energy Efficiency Programs pursuant to the New Mexico Efficient Use of Energy Act. The filing included changes and additions to the Company's previously approved programs and sought revisions to the associated rate rider through which program costs are recovered. The parties to the proceeding entered into an uncontested stipulation to implement program changes and expansions as well as the rate rider to recover related costs. The NMPRC approved the stipulation in its final order issued August 12, 2010.

2010 Renewable Procurement Plan Pursuant to the Renewable Energy Act. On July 1, 2010, the Company filed its Application for Approval of its 2010 Renewable Procurement Plan, which was assigned NMPRC Case No. 10-00200-UT. The filing included renewable resources intended to meet the Company's Renewable Portfolio Standard ("RPS") requirements in 2011 and future years. The 2010 Renewable Procurement Plan included a number of projects to meet the Company's RPS requirements, including three purchased power agreements for solar energy discussed in "Energy Sources – Purchased Power." In addition, the Company requested a variance from the solar diversity requirements in 2011 to be made up in later years from the new purchased power agreements for solar energy. Hearings were held on October 21, 2010. A final order was issued on December 16, 2010 that approved the Company's 2010 Renewable Procurement plan, including granting the requested variance from the solar diversity requirements in 2011. However, the NMPRC maintained the 2010 rates and contract terms for energy produced by customer-owned renewable distributed generation facilities.

Replacement of Revolving Credit Facility and Guarantee of Debt. On June 22, 2010, the Company received final approval from the NMPRC in Case No. 10-00145-UT to refinance the Company's RCF and issue in a private placement up to $110 million of senior notes by the RGRT, guaranteed by the Company, to finance nuclear fuel. The refinancing of the RCF and the issuance of the senior notes was completed in the third quarter of 2010. See "Energy Sources – Nuclear Fuel – Nuclear Fuel Financing."

Application for Approval to Recover Regulatory Disincentives and Incentives. On August 31, 2010, the Company filed an application for approval of its proposed rate design methodology to recover regulatory disincentives and incentives associated with the Company's energy efficiency and load management programs in New Mexico. A hearing is scheduled for April 25, 2011 and a final order is expected before July 2011.

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, Case No. 07-00443-UT, the NMPRC required each utility to provide information on compensation of executive officers and directors for the period 1977-2006. The Company provided the requested information. No further action was taken by the NMPRC and the case was closed on October 5, 2010.

Application for a Certificate of Convenience and Necessity for Rio Grande Unit 9. On September 30, 2010, the Company filed a petition seeking a Certificate of Convenience and Necessity to construct an 87 MW natural gas-fired combustion turbine unit at the Company's existing Rio Grande Generating Station in the City of Sunland Park in southeast New Mexico. This case was assigned NMPRC Case No. 10-00301-UT. The hearing is scheduled to begin April 13, 2011.

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 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 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, and hearings on the disputed issues were held before an administrative law judge. In the initial decision dated September 6, 2007, the administrative law judge found that the Transmission Agreement allows TEP to transmit power from the LEF 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 exceptions to the initial decision.

On November 13, 2008, the FERC issued an order on the initial decision finding that the transmission rights given to TEP in the Transmission Agreement are firm and are not restricted for transmission of power from Springerville as the receipt point to Greenlee as the delivery point. Therefore, pursuant to the order, TEP can use its transmission rights granted under the Transmission Agreement to transmit power from the LEF to either Springerville or Greenlee so long as it transmits no more than 200 MW over all segments at any one time.

The FERC also ordered that the Company refund to TEP all sums with interest that TEP had paid it for transmission under the applicable transmission service agreements since February 2006 for service relating to the LEF. On December 3, 2008, the Company refunded $9.7 million to TEP. The Company had established a reserve for the rate refund of approximately $7.2 million as of September 30, 2008, resulting in a pre-tax charge to earnings of approximately $2.5 million in 2008. The Company also paid TEP interest on the refunded balance of approximately $0.9 million, which was also charged to earnings in 2008. The Company filed a request for rehearing of the FERC's decision on December 15, 2008, seeking reversal of the order on the merits and a return of any refunds made in the interim, as well as compensation for all service that the Company may provide to TEP from the LEF over the Company's transmission system on a going forward basis. On July 7, 2010, the FERC denied the Company's request for rehearing. On July 23, 2010, the Company filed a petition for review in the United States Court of Appeals for the District of Columbia Circuit and on August 18, 2010, TEP filed a motion to intervene in the proceeding. On January 14, 2011, the Company and TEP filed a joint consent motion, asking the Court to hold the proceedings in abeyance while the parties engaged in settlement discussions. The Court granted the motion on January 19, 2011. If the order is not reversed, or otherwise resolved through settlement, the Company will lose the opportunity to receive compensation from TEP for such transmission service in the future.

In an ancillary proceeding, TEP filed a lawsuit in the United States District Court for the District of Arizona in December 2008, seeking reimbursement for amounts TEP paid a third party transmission provider for purchases of transmission capacity between April 2006 and May 2007, allegedly totaling approximately $1.5 million, plus accrued interest. TEP alleges that the Company was obligated to provide TEP with that transmission capacity without charge under the Transmission Agreement. In September 2009, the Court granted a stay in this suit pending a resolution of the underlying FERC proceeding and any appeal thereof. The Company cannot predict the outcome of this matter.

Replacement of Revolving Credit Facility and Guarantee of Debt. On June 29, 2010, the Company received approval from the FERC in Docket No. ES10-43-000 to refinance the Company's RCF and issue in a private placement up to $110 million of senior notes by the RGRT, guaranteed by the Company, to finance nuclear fuel. The refinancing of the RCF and the issuance of the senior notes was completed in the third quarter of 2010. See "Energy Sources – Nuclear Fuel – Nuclear Fuel Financing."

Department of Energy. The DOE regulates the Company's exports of power to the Comisión Federal de Electricidad 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. See "Facilities – Palo Verde Station" for discussion regarding application to extend the Palo Verde licenses for 20 years.

Sales for Resale

The Company provides firm capacity and associated energy to the RGEC pursuant to an ongoing contract which requires a two-year notice to terminate. The Company also provides network integrated transmission service to RGEC pursuant to the Company's Open Access Transmission Tariff ("OATT"). The contract includes a formula-based rate that is updated annually to recover non-fuel generation costs and a fuel adjustment clause designed to recover all eligible fuel and purchased power costs allocable to RGEC.

Power Sales Contracts

The Company has entered into several short-term (three months or less) off-system sales contracts throughout 2011.

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, entered into in July 2005, included a franchise fee of 3.25% of revenues. Effective August 2010, the franchise fee was increased to 4%. The additional fee of 0.75% is to be placed in a restricted fund to be used solely for economic development and renewable energy purposes. The franchise agreement 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 for the provision of electric distribution service. Las Cruces exercised its right to extend the franchise for an additional two-year term which ended April 30, 2009 and waived its option to purchase the Company's distribution system pursuant to the terms of the February 2000 settlement agreement. The Company is currently operating under an implied franchise by satisfying all obligations under the expired franchise.

Military Installations

The Company currently serves Holloman Air Force Base ("Holloman"), White Sands Missile Range ("White Sands") and Fort Bliss. The Company's sales to the military bases represent approximately 4% of annual retail revenues. The Company signed a contract with Ft. Bliss in October 2008 under which Ft. Bliss takes retail electric service from the Company. The contract with Ft. Bliss expired in 2010 and the Company is serving Ft. Bliss under the applicable Texas tariffs. In April 1999, the Army and the Company entered into a ten-year contract to provide retail electric service to White Sands. The contract with White Sands expired in 2009 and the Company is serving White Sands under the applicable New Mexico tariffs. 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 Revenues and Profitability Depend upon Regulated Rates

Our retail rates are subject to regulation by incorporated municipalities in Texas, the PUCT, the NMPRC and the FERC. The settlement approved in the Company's 2009 Texas rate case, PUCT Docket No. 37690, established the Company's current retail base rates in Texas, effective July 1, 2010. In addition, the settlement in the Company's 2009 New Mexico rate case, NMPRC Case No. 09-00171-UT, established rates that became effective January 2010. The Company continually evaluates the need to file general base rate cases in Texas and New Mexico to incorporate increases in invested capital and costs.

Our profitability depends on our ability to recover the costs, including a reasonable return on invested capital, of providing electric service to our customers through base rates approved by our regulators. These rates are generally established based on an analysis of the expenses we incur in a historical test year, and as a result, the rates ultimately approved by our regulators may or may not match our expenses at any given time. Rates in New Mexico may be established using projected costs and investment for a future test year period in certain instances. While rate regulation is based on the assumption that we will have a reasonable opportunity to recover our costs and earn a reasonable rate of return on our invested capital, there can be no assurance that future rate cases will result in base rates that will allow us to fully recover our costs including a reasonable return on invested capital. There can be no assurance that regulators will determine that all of our costs are reasonable and have been prudently incurred. It is also likely that third parties will intervene in any rate cases and challenge whether our costs are reasonable and necessary. If all of our costs are not recovered through the retail base rates ultimately approved by our regulators, our profitability and cash flow could be adversely affected which, over time, could adversely affect our ability to meet our financial obligations.

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

The construction of Newman Unit 5, Phase 2, will add two heat recovery steam generators and a steam turbine with an expected net capacity of 148 MW. Phase 2 is currently expected to be completed before the summer of 2011. We have risk associated with completing the construction of Newman Unit 5 on time and within projected costs.

In 2010, we established a new revolving credit facility which could help fund the construction of these two new units. The costs of financing and constructing these units will be reviewed in future rate cases in both Texas and New Mexico. To the extent that the PUCT 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 these units are 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 PUCT 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 these two units.

Turmoil in the Credit Markets and Economic Downturn

In recent years, the global credit and equity markets and the overall economy have been through a state of turmoil and have not fully recovered. These events could have a number of effects on our operations and our capital programs. For example, tight credit and capital markets could make it difficult and more expensive to raise capital to fund our operations and capital programs. If we are unable to access the credit markets, we could be required to defer or eliminate important capital projects in the future. In addition, recent stock market performance has provided limited returns on our financial assets and decommissioning trust investments. Such market results may also increase our funding obligations for our pension plans, other post-retirement benefit plans and nuclear decommissioning trusts. Changes in the corporate interest rates which we use as the discount rate to determine our pension and other post-retirement liabilities may have an impact on our funding obligations for such plans and trusts. Further, the continued weak economy may result in reduced customer demand, both in the retail and wholesale markets, and increases in customer delinquencies and write-offs. The credit markets and overall economy may also adversely impact the financial health of our suppliers. If that were to occur, our access to and prices for inventory, supplies and capital equipment could be adversely affected. Our power trading counterparties could also be adversely impacted by the market and economic conditions which could result in reduced wholesale power sales or increased counterparty credit risk. This is not intended to be an exhaustive list of possible effects, and we may be adversely impacted in other ways.

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 39% of our available net generating capacity and provided approximately 45% of our energy requirements for the twelve months ended December 31, 2010. Palo Verde comprises approximately 37% 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 90.4% and 88.9% in the twelve months ended December 31, 2010 and 2009, respectively.

Our ability to increase retail base rates in Texas and New Mexico is limited and 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 reasonable and necessary fuel and purchased power expenses from our customers in Texas and New Mexico. NMPRC Case No. 09-00171-UT provides for energy delivered to New Mexico customers from the deregulated Palo Verde Unit 3 to be recovered through fuel and purchased power costs based upon a previous purchased power contract with Credit Suisse Energy, LLC. Fuel and purchased power expenses in New Mexico and Texas are subject to reconciliation by the PUCT and the NMPRC. Prior to the completion of a reconciliation, we record fuel and purchased power costs such that fuel revenues equal recoverable fuel and purchased power expense including the repriced energy costs for Palo Verde Unit 3 in New Mexico. In the event that recovery of fuel and purchased power expenses is denied in 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. Effective July 1, 2010, we can seek to revise our fixed fuel factor based upon our approved formula at least four months after our last revision except in the month of December. If we materially under-recover fuel costs, we may seek a surcharge to recover those costs at any time the balance exceeds a threshold material amount and is expected to continue to be materially under-recovered. During periods of significant increases in natural gas prices such as occurred in the first eight months of 2008, 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. 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. At December 31, 2010 and 2009, the Company had a net over-collection balance of $19.0 million and $18.0 million, respectively.

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 and severe weather conditions. The advanced age of several of our gas-fired generating units in or near El Paso increases the vulnerability of these units. 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 additional purchased power cost would be subject to review and approval of the PUCT and the NMPRC in reconciliation proceedings. As noted above, in the event that recovery for fuel and purchased power expenses could differ from the amounts we are allowed to collect from our customers, we would incur a loss to the extent of the disallowance. 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 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 flow and financial position.

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, alternative 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 PUCT 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 a regional transmission organization in the area that includes our service territory. This and other milestones are not likely to be achieved for a number of years, if they are achieved at all. 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 flow and financial condition.

Furthermore, in an order dated December 17, 2009, the NMPRC concluded that certain third party developers who own renewable generation which is installed on utility customers' premises to supply one or more customers with a portion of their electricity needs, payments for which are based on a kW charge, are not public utilities subject to regulation by the NMPRC. The New Mexico legislature passed legislation which was signed by the governor on May 9, 2010 establishing the circumstances under which certain third-party suppliers would be permitted to compete with the Company on a limited basis beginning in January 2011. There can be no assurance that such competition would not adversely affect our future operations, cash flow and financial condition.

Climate Change and Related Legislation and Regulatory Initiatives Could Affect Demand for Electricity or Availability of Resources, and Could Result in Increased Compliance Costs

The Company emits GHGs through the operation of its power plants. Federal legislation has been introduced in both houses of Congress to regulate the emission of GHGs and numerous states have adopted programs to stabilize or reduce GHG emissions. Additionally, the EPA is proceeding with regulation of GHG under the CAA. Under EPA regulations finalized in May 2010, the EPA began regulating GHG emissions from certain stationary sources, such as power plants, in January 2011. Further, state regulation may precede federal GHG legislation. In the State of New Mexico, where we operate one facility and have an interest in another facility, the New Mexico Environmental Improvement Board approved two separate rulemakings in November and December 2010 to limit GHG emissions. There are various uncertainties relating to these regulations, including whether current legal challenges to them will be successful, but as drafted, we do not expect these regulations to result in significant costs to us.

It is not currently possible to predict how any pending, proposed or future GHG legislation by Congress, the states or multi-state regions or any regulations adopted by the EPA or state environmental agencies will impact our business. However, any such legislation or regulation of GHG emissions or any future related litigation could result in increased compliance costs or additional operating restrictions or increased or reduced demand for our services, could require us to purchase rights to emit GHGs, and could have a material adverse effect on our business, financial condition, reputation or results of operations.

Climate change also has potential physical effects that could be relevant to the Company's business. In particular, some studies suggest that climate change could affect our service area by causing higher temperatures, less winter precipitation and less spring runoff, as well as by causing more extreme weather events. Such developments could change the demand for power in the region and could also impact the price or ready availability of water supplies and affect maintenance needs and the reliability of Company equipment. Given the very significant remaining uncertainties regarding whether and how these issues will be regulated, as well as the timing and severity of any physical effects of climate change, we believe it is impossible at present to meaningfully quantify the costs of these potential impacts.

Item 1B. Unresolved Staff Comments

None.

Executive Officers of the Registrant

The executive officers of the Company as of February 15, 2011, were as follows:

Name	Age	Current Position and Business Experience
David W. Stevens	51	Chief Executive Officer since November 2008; Principal of Professional Consulting Services, LLC from December 2007 to November 2008; President, Chief Executive Officer and Board Member for Cascade Natural Gas Corporation from April 2005 to July 2007.
David G. Carpenter	55	Senior Vice President and Chief Financial Officer since August 2009; Vice President – Regulatory Services and Controller from September 2008 to August 2009; Vice President – Corporate Planning and Controller from August 2005 to September 2008.
Richard G. Fleager	60	Senior Vice President – Customer Care and External Affairs since April 2009; Vice President for Texas Gas Service from September 1997 to March 2009.
Mary E. Kipp	43	Senior Vice President, General Counsel and Chief Compliance Officer since June 2010; Vice President – Legal and Chief Compliance Officer from December 2009 to June 2010; Assistant General Counsel and Director of FERC Compliance from December 2007 to December 2009; Senior Enforcement Attorney – FERC from January 2004 to December 2007.
Rocky R. Miracle	57	Senior Vice President – Corporate Planning and Development since August 2009; Vice President – Corporate Planning from September 2008 to August 2009; Director of Business Operations Support – Texas Operations for American Electric Power Services Corporation from August 2004 to August 2008.
Steven T. Buraczyk	43	Vice President – System Operations and Planning since January 2011; Vice President – Power Marketing and Fuels from July 2008 to January 2011; Director of Power Marketing and Fuels from August 2006 to July 2008; Manager of Power Marketing from August 2004 to August 2006.
Steven P. Busser	42	Vice President – Treasurer since January 2011; Vice President – Treasurer and Chief Risk Officer from May 2006 to January 2011; Vice President – Regulatory Affairs and Treasurer from February 2005 to April 2006.
Robert C. Doyle	51	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.
Nathan T. Hirschi	47	Vice President and Controller since March 2010; Vice President – Special Projects from December 2009 to February 2010; Partner for KPMG LLP from October 2003 to April 2009.
Kerry B. Lore	51	Vice President – Customer Care since December 2008; Vice President – Administration from May 2003 to December 2008.
Hector R. Puente	54	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 R. Ramirez	50	Vice President – Power Generation since February 2006; Vice President – Safety, Environmental and Resource Planning from July 2005 to February 2006.
Guillermo Silva, Jr.	57	Corporate Secretary since February 2006; Vice President – Information Services from February 2003 to February 2006.
John A. Whitacre	61	Vice President – Power Marketing and Fuels since January 2011; Vice President – System Operations and Planning from May 2006 to January 2011; 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 February 2008, the Company purchased the executive and administrative office building in El Paso that it had previously leased. In June 2008, the Company entered into an agreement to lease land in El Paso adjacent to the Newman Power Station under a lease which expires in June 2033 with a renewal option of 25 years.

In addition, the Company leases certain warehouse facilities in El Paso under a lease which expires in December 2014. The Company also has several other leases for office and parking facilities which expire within the next five 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.

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

Item 4. Removed and Reserved

PART II

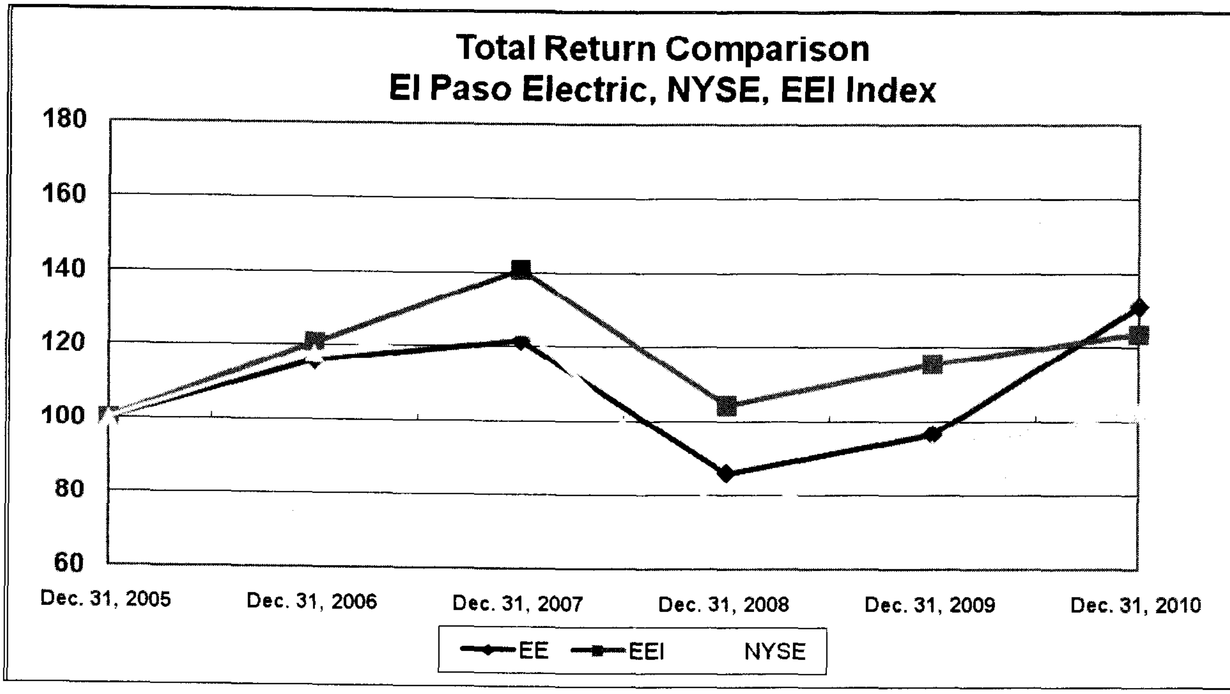
Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.

The Company's common stock trades on the New York Stock Exchange ("NYSE") 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)**
2009			
First Quarter	$ 18.78	$ 11.65	$ 14.09
Second Quarter	15.08	12.95	13.96
Third Quarter	18.12	13.85	17.67
Fourth Quarter	21.11	17.40	20.28
2010			
First Quarter	$ 20.98	$ 18.74	$ 20.60
Second Quarter	22.15	18.76	19.35
Third Quarter	23.82	18.81	23.78
Fourth Quarter	28.65	23.51	27.53

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, 2005 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.



	12/31/05	12/31/06	12/31/07	12/31/08	12/31/09	12/31/10
EE	100	116	122	86	96	131
EEI	100	121	141	104	115	124
NYSE US	100	118	126	74	93	103

As of January 31, 2011, there were 3,448 holders of record of the Company's common stock. The Company does not currently pay dividends on its common stock. Since 1999, the Company has returned cash to stockholders through a stock repurchase program pursuant to which the Company has bought approximately 22.6 million shares at an aggregate cost of $337.1 million, including commissions. Under the Company's program, purchases can be made at open market prices or in private transactions and repurchased shares are available for issuance under employee benefit and stock incentive plans, or may be retired. On February 19, 2010, the Board of Directors authorized a repurchase of up to two million shares of the Company's outstanding common stock (the "2010 Plan"). During the twelve months ended December 31, 2010, the Company repurchased 1,524,711 shares of common stock in the open market at an aggregate cost of $33.7 million under both a previously authorized program and under the 2010 Plan. During the fourth quarter of 2010, the Company repurchased 133,662 shares at an aggregate cost of $3.5 million. The table below provides the amount of the fourth quarter repurchases on a monthly basis.

Period	Total Number of Shares Purchased	Average Price Paid per Share (Including Commissions)	Total Number of Shares Purchased as Part of a Publicly Announced Program	Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs
October 1 to October 31, 2010	0	$ 0.00	0	809,933
November 1 to November 30, 2010	133,662	26.25	133,662	676,271
December 1 to December 31, 2010	0	0.00	0	676,271

As of December 31, 2010, 676,271 shares remain eligible for repurchase under the 2010 Plan. The Company's Board is currently analyzing the relative advantages of providing the Company's stockholders a cash return on their investment through a cash dividend instead of, or in addition to, the Company's current program.

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 and per share data):

	Years Ended December 31,				
	2010	2009	2008	2007	2006
Operating revenues	$ 877,251	$ 827,996	$ 1,038,930	$ 877,427	$ 816,455
Operating income	$ 168,962	$ 133,165	$ 145,736	$ 128,321	$ 115,562
Income before extraordinary items	$ 90,317	$ 66,933	$ 77,621	$ 74,753	$ 61,387
Extraordinary gain, net of tax (a)	$ 10,286	$ 0	$ 0	$ 0	$ 6,063
Net income	$ 100,603	$ 66,933	$ 77,621	$ 74,753	$ 67,450
Basic earnings per share:					
Income before extraordinary items	$ 2.08	$ 1.50	$ 1.73	$ 1.64	$ 1.28
Extraordinary gain (a)	$ 0.24	$ 0.00	$ 0.00	$ 0.00	$ 0.13
Net income	$ 2.32	$ 1.50	$ 1.73	$ 1.64	$ 1.41
Weighted average number of shares outstanding	43,129,735	44,524,146	44,777,765	45,563,858	47,663,890
Diluted earnings per share:					
Income before extraordinary items	$ 2.07	$ 1.50	$ 1.72	$ 1.63	$ 1.27
Extraordinary gain (a)	$ 0.24	$ 0.00	$ 0.00	$ 0.00	$ 0.13
Net income	$ 2.31	$ 1.50	$ 1.72	$ 1.63	$ 1.40
Weighted average number of shares and dilutive potential shares outstanding	43,294,419	44,595,067	44,930,109	45,873,018	48,106,608
Cash additions to utility property, plant and equipment	$ 169,966	$ 209,974	$ 198,711	$ 144,588	$ 103,182
Total assets	$ 2,364,766	$ 2,226,152	$ 2,069,083	$ 1,853,888	$ 1,714,654
Long-term debt and financing obligations, net of current portion	$ 849,745	$ 804,975	$ 809,718	$ 655,111	$ 616,130
Common stock equity	$ 810,375	$ 722,729	$ 694,229	$ 666,459	$ 579,675

(a) Extraordinary gain for 2010 includes a $10.3 million extraordinary gain or $0.24 earnings per share related to Texas regulatory assets. Extraordinary gain for 2006 includes a $6.1 million extraordinary gain or $0.13 earnings per share on the re-application of FASB guidance for regulated operations.

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

Our consolidated financial statements have been prepared in conformity with GAAP. Note A to the consolidated financial statements contains a summary of our significant accounting policies, many of which require the use of estimates and assumptions. We believe that of our significant accounting policies, the following are noteworthy because they are based on estimates and assumptions that require complex, subjective assumptions by management, which can materially impact reported results. Changes in these estimates or assumptions, or actual results that are different, could materially impact our financial condition and results of operation.

Regulatory Accounting

We apply accounting standards that recognize the economic effects of rate regulation in our Texas, New Mexico and FERC jurisdictions. As a result, we record certain costs or obligations as either assets or liabilities on our balance sheet and amortize them in subsequent periods as they are reflected in regulated rates. The deferral of costs as regulatory assets is appropriate only when the future recovery of such costs is probable. In assessing probability, we consider such factors as specific regulatory orders, regulatory precedent and the current regulatory environment. As of December 31, 2010, we had recorded regulatory assets currently subject to recovery in future rates of approximately $88.6 million and regulatory liabilities of approximately $14.5 million as discussed in greater detail in Note C of the Notes to the Consolidated Financial Statements. In the event we determine that we can no longer apply the FASB guidance for regulated operations to all or a portion of our operations or to the individual regulatory assets recorded, 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.

Collection of Fuel Expense

In general, by law and regulation, our actual 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 PUCT and the NMPRC. Prior to the completion of a reconciliation proceeding, we record fuel transactions such that fuel revenues, including fuel costs recovered through base rates in New Mexico, equal fuel expense. In the event that a disallowance of fuel cost recovery 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. The determination of the estimated liability requires the use of various assumptions pertaining to decommissioning costs, escalation and discount rates. We determine how we will fund our share of those estimated costs by making assumptions about future investment returns and future decommissioning cost escalations. Decommissioning costs will be adjusted prospectively for future changes in estimated decommissioning costs and when actual costs are incurred to decommission the plant. Decommissioning costs and our asset retirement obligation will also be adjusted if the NRC approves the application to extend the Palo Verde licenses for 20 years. Further, if the rates of return earned by the trusts fail to meet expectations or if estimated costs to decommission the plant increase, we could be required to increase our funding to the decommissioning trust accounts. Historically, we have been permitted to collect in rates in Texas and New Mexico the costs of nuclear decommissioning.

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 rates, expected return on plan assets, rate of compensation increase, life expectancy of retirees and health care cost inflation. 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.

Tax Accruals

We use the asset and liability method of accounting for income taxes. Under this method, we recognize deferred tax assets and liabilities for the future tax consequences attributable to temporary differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities. The application of income tax law and regulations is complex and we must make judgments regarding income tax exposures. Changes in these judgments, due to changes in law, regulation, interpretation, or audit adjustments can materially affect amounts we recognize in our consolidated financial statements.

Overview

The following is an overview of our results of operations for the years ended December 31, 2010, 2009 and 2008. Income before extraordinary item for the years ended December 31, 2010, 2009 and 2008 is shown below:

	Years Ended December 31,		
	2010	**2009**	**2008**
Income before extraordinary item (in thousands)...............	$ 90,317	$ 66,933	$ 77,621
Basic earnings per share before extraordinary item............	2.08	1.50	1.73

The following table and accompanying explanations show the primary factors affecting the after-tax change in income before extraordinary item between the calendar years ended 2010 and 2009, 2009 and 2008, and 2008 and 2007 (in thousands):

	2010	2009	2008
Prior year December 31 income before extraordinary item	$ 66,933	$ 77,621	$ 74,753
Change in (net of tax):			
Increased retail non-fuel base revenues	33,395 (a)	8,292 (b)	3,547 (c)
Increased AFUDC and capitalized interest	2,882 (d)	641	3,456 (e)
Decreased (increased) Palo Verde operations and maintenance expense	2,753 (f)	(2,266)(g)	(7,737)(h)
Increased transmission wheeling revenue	1,446	1,887 (i)	2,643 (j)
Increased (decreased) investment and interest income	1,302 (k)	122	(3,659)(l)
Increased (decreased) deregulated Palo Verde Unit 3 revenues	1,235 (m)	(7,121)(n)	11,938 (o)
Decreased (increased) depreciation and amortization	(3,821)(p)	393	(3,890)(q)
Decreased (increased) administrative and general expense	(3,502)(r)	(2,544)(s)	2,066 (t)
Increased (decreased) off-system sales margins retained	(3,224)(u)	(7,140)(v)	4,172 (w)
Increased taxes other than income taxes	(2,830)(x)	(121)	(374)
Decreased (increased) customer account and service expense	(2,445)(y)	(483)	695
Decreased (increased) maintenance at coal and gas-fired generating plants	(1,120)	1,719	(3,630)(z)
Increased interest on long-term debt	(198)	(1,832)(aa)	(6,779)(aa)
Elimination of Medicare Part D tax benefit	(4,787)(bb)	0	0
Other	2,298	(2,235)	420
Current year December 31 income before extraordinary item	$ 90,317	$ 66,933	$ 77,621

(a) Retail non-fuel base revenues increased in 2010 compared to 2009 primarily due to new non-fuel base rates in New Mexico and Texas to recover capital investments to meet customer growth and a 4.4% increase in retail kWh sales. Retail non-fuel base revenues exclude fuel recovered through New Mexico base rates.

(b) Retail non-fuel base revenues increased in 2009 compared to 2008 primarily due to increased kWh sales to residential customers and public authorities partially offset by a decrease in kWh sales to large commercial and industrial customers.

(c) Retail non-fuel base revenues increased in 2008 compared to 2007 largely due to increased kWh sales to small commercial and industrial customers and public authorities.

(d) AFUDC (allowance for funds used during construction) and capitalized interest increased in 2010 compared to 2009 primarily due to higher balances of construction work in progress subject to AFUDC.

(e) AFUDC increased for 2008 compared to 2007 due to increased construction work in progress subject to AFUDC.

(f) Palo Verde operations and maintenance expense decreased in 2010 compared to 2009 primarily due to decreased maintenance costs at Units 2 and 3 as the result of reduced costs for scheduled refueling outages.

(g) Palo Verde non-fuel operations and maintenance expense increased for 2009 compared to 2008 due to increased employee benefit expense and increased operating costs, partially offset by decreased maintenance costs in 2009.

(h) Palo Verde non-fuel operations and maintenance expenses increased due to increased operating costs at all three units in 2008 and higher maintenance costs during refueling outages in 2008 than during refueling outages during 2007.

(i) Transmission wheeling for 2009 increased due to the reversal of $2.5 million of 2006 wheeling revenues from Tucson Electric Power pursuant to an order of the FERC in 2008.

(j) Transmission wheeling for 2008 increased largely due to wheeling power in southern New Mexico and Arizona partially offset by the reversal of $2.5 million of 2006 wheeling revenues from Tucson Electric Power pursuant to an order of the FERC.

(k) Investment and interest income increased in 2010 compared to 2009 primarily due to $2.2 million in impairment and net realized losses on investment in our Palo Verde decommissioning trusts in 2009 compared to $0.1 million in impairment and net realized losses in 2010.

(l) Lower investment and interest income in 2008 compared to 2007 is primarily due to impairments of equity securities in our Palo Verde decommissioning trust funds and a decrease in the fair value of our investments in auction rate securities.

(m) Revenues from retail sales of deregulated Palo Verde Unit 3 power increased due to increased production at Palo Verde Unit 3 in 2010 and higher proxy prices in 2010.

(n) Deregulated Palo Verde Unit 3 revenues in 2009 reflect lower proxy market prices and lower sales of the deregulated portion of Palo Verde Unit 3 to retail customers due mostly to its planned refueling outage in April and May 2009.

(o) In 2008, deregulated Palo Verde Unit 3 revenues reflect higher proxy market prices and increased sales of the deregulated portion of Palo Verde Unit 3 to retail customers when compared to 2007 as the unit did not operate in the fourth quarter of 2007 due to its refueling and replacement of steam generators.

(p) Depreciation and amortization expense increased in 2010 compared to 2009 due to increased depreciable plant balances and increased depreciation rates.

(q) Depreciation and amortization expense increased due to increased plant balances including the replacement of Palo Verde Unit 3 steam generators in January 2008.

(r) Administrative and general expenses increased in 2010 compare to 2009 primarily due to increased pension and benefits expense as a result of changes in actuarial assumptions used to calculate expenses for our pension plan.

(s) Administrative and general expenses increased in 2009 compared to 2008 primarily due to increased accruals for employee incentive compensation and increased pension and benefits expenses reflecting a lower discount rate used to determine postretirement benefit costs.
(t) Administrative and general expenses decreased in 2008 compared to 2007 primarily due to lower pension and other post-retirement benefits expenses reflecting an increase in the discount rate for the associated liabilities.
(u) Off-system sales margins decreased in 2010 compared to 2009 due to increased sharing of off-system sales margins with customers from 25% to 90% effective July 1, 2010 consistent with prior rate agreements in Texas and New Mexico.
(v) Lower retained margins on off-system sales in 2009 compared to 2008 are primarily the result of reduced margins per MWh due to lower market prices and a decline in MWh sales.
(w) Higher retained margins on off-system sales in 2008 compared to 2007 are primarily the result of increased sales and margins from off-system sales to a wholesale customer.
(x) Taxes other than income taxes increased in 2010 compared to 2009 due to revenue-related taxes and increased property taxes.
(y) Customer accounts and service expense increased in 2010 compared to 2009 primarily due to the transition to our new customer billing system and increased uncollectible customer accounts.
(z) In 2008 operation and maintenance costs increased at our fossil-fueled generating plants as planned major maintenance was performed at Newman Unit 3 and Four Corners Unit 5. In 2007 no major maintenance was performed at our fossil-fueled generating units.
(aa) Interest expense on long-term debt increased for 2009 compared to 2008 and 2008 compared to 2007 due to the issuance of $150 million of 7.5% Senior Notes in June 2008 and higher interest rates on auction rate pollution control bonds in 2008.
(bb) Tax expense increased in 2010 to recognize a change in tax law enacted in the Patient Protection and Affordable Care Act to eliminate the tax benefit related to the Medicare Part D subsidies.

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. We shared 25% of off-system sales margins with our Texas and New Mexico customers and retained 75% of off-system sales margins through June 30, 2010. Pursuant to rate agreements in prior years, effective July 1, 2010, we share 90% of off-system sales margins with our Texas and New Mexico customers, and we retain 10% of off-system sales margins. We are sharing 25% of our off-system sales margins with our sales for resale customer under the terms of a contract which was effective April 1, 2008.

Revenues from the sale of electricity include fuel costs that are recovered from our customers through fuel adjustment mechanisms. A significant portion of fuel costs are also recovered through base rates in New Mexico. We record deferred fuel revenues for the difference between actual fuel costs and recoverable 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 recovery of such fuel costs.

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

	Twelve Months Ended December 31,		
	2010	2009	2008
Residential	41%	41%	39%
Commercial and industrial, small	35	36	37
Commercial and industrial, large	8	7	8
Sales to public authorities	16	16	16
Total retail non-fuel base revenues	100%	100%	100%

No retail customer accounted for more than 3% of our non-fuel base revenues during such periods. As shown in the table above, residential and small commercial customers comprise more than 75% of our revenues. While this customer base is more stable, it is also more sensitive to changes in weather conditions. The new rate structure in New Mexico and Texas increases base rates during the peak summer season of May through October while decreasing base rates during November through April for our residential and small commercial and industrial customers. 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 retail non-fuel base revenues derived during each quarter for the periods presented:

	Years Ended December 31,		
	2010	2009	2008
January 1 to March 31	21%	21%	22%
April 1 to June 30	24	26	26
July 1 to September 30	33	30	29
October 1 to December 31	22	23	23
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 2010, 2009 and 2008.

	2010	2009	2008	10-year Average
Heating degree days	2,273	2,144	2,167	2,280
Cooling degree days	2,738	2,768	2,253	2,562

Customer growth is a key driver in the growth of retail sales. The average number of retail customers grew 1.7% in both 2010 and 2009. 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. The new rate structure in New Mexico, effective January 1, 2010, and in Texas, effective July 1, 2010, increases base rates during the peak summer season of May through October while decreasing base rates during November through April for our residential and small commercial and industrial customers. This will cause our revenues to be more seasonal than in the past.

Retail non-fuel base revenues increased by $53.0 million or 11.0% for the twelve months ended December 31, 2010 when compared to the same period in 2009. The increase was primarily due to new non-fuel base rates in New Mexico and Texas and a 4.4% increase in retail kWh sales driven by improving local economic conditions. KWh sales to residential customers increased 6.2% reflecting a 1.8% growth in the average number of customers served and colder winter weather in the first quarter of 2010. During the twelve months ended December 31, 2010, heating degree days were 6% above the same period in 2009 and at the 10-year average. KWh sales to small commercial and industrial customers increased 2.0% reflecting a 1.4% increase in the average number of small commercial and industrial customers served. Retail non-fuel base revenues also increased due to a 26% increase in non-fuel base revenues from large commercial and industrial customers attributable to increased kWh sales to large commercial and industrial customers of 6.2% and the implementation of higher rates in new contracts and tariff rates with several large customers whose contracts had expired. KWh sales to public authorities increased 4.0% largely due to increased sales to military bases.

Retail non-fuel base revenues increased by $13.2 million or 2.8% for the twelve months ended December 31, 2009 when compared to the same period in 2008 as a result of an increase of 6.0% in kWh sales to residential customers and a 2.3% increase in kWh sales to public authorities. Residential sales increased as a result of hotter summer weather in 2009 compared to 2008 and growth of 1.8% in the average number of residential customers served. Cooling degree days in 2009 were 23% higher than in 2008 and 8% above the 10-year average. Sales to other public authorities reflect increased sales to military bases. These increases were partially offset by a recession-related decline in sales to large commercial and industrial customers. Revenues from large commercial and industrial customers decreased 4.2% in the twelve months ended December 31, 2009 compared to the same period in 2008.

Fuel revenues. Fuel revenues consist of: (i) revenues collected from customers under fuel recovery mechanisms approved by the state commissions and the FERC, (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 and with our sales for resale customer, the fuel adjustment clause allows us to recover under-recoveries or refund over-recoveries of current fuel costs above the amount recovered in base rates with a two-month lag. In Texas, fuel costs are recovered through a fixed fuel factor. Effective July 1, 2010, we can seek to revise our fixed fuel factor based upon our approved formula at least four months after our last revision except in the month of December. 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.

We over-recovered fuel costs by $35.4 million and $66.6 million in the twelve months ended December 31, 2010 and 2009, respectively. In the twelve months ended December 31, 2008, we under-recovered fuel costs by $42.8 million. In 2008, we implemented two fuel surcharges in Texas to collect fuel under-recovery balances. However, natural gas prices decreased significantly after August 2008 and both of these surcharges were terminated effective with May 2009 billings. In July 2009, we received approval from the PUCT to reduce our fixed fuel factor in Texas effective in August 2009, and in October 2009, we received approval from the PUCT to refund to customers fuel over-recoveries through August 2009 of $16.8 million, plus interest in November and December 2009. In January 2010, we received approval in Texas for an interim refund of fuel over-recoveries incurred through November 2009 of $11.8 million, with interest, to be refunded to customers in February 2010. In addition, in June 2010, we received approval from the PUCT to refund to customers fuel over-recoveries for the period from December 2009 through March 2010 of $11.1 million plus interest in July and August 2010. In December 2010, we received approval to refund to customers fuel over-recoveries for the period from July 2009 through September 2010 of $12.8 million plus interest in December 2010. At December 31, 2010, we had a fuel over-recovery balance of $19.0 million, including $14.2 million in Texas and $4.8 million in New Mexico. Over-recoveries in New Mexico will be refunded through our fuel adjustment clause during 2011.

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 a significant portion 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 costs, total margins, and retained margins made on off-system sales for the twelve months ended December 31, 2010, 2009 and 2008 (in thousands except for MWhs).

	Twelve Months Ended December 31,		
	2010	2009	2008
MWh sales	2,822,732	2,995,984	3,506,770
Sales revenues	$ 105,317	$ 116,064	$ 232,500
Fuel cost	$ 93,516	$ 101,665	$ 203,021
Total margins	$ 11,801	$ 14,399	$ 29,479
Retained margins	$ 5,687	$ 10,803	$ 22,137

Off-system sales revenues decreased $10.7 million or 9.3% for the twelve months ended December 31, 2010 when compared to 2009 as a result of lower average market prices for power and a 5.8% decline in MWh sales. For the twelve months ended December 31, 2010, retained margins decreased $5.1 million or 47.4% when compared to the same period in 2009. Customers were credited with 25% of the off-system sales margins through fuel recovery mechanisms through June 30, 2010. In July 2010, off-system sales margins shared with customers in Texas and New Mexico increased to 90%. Off-system sales decreased $116.4 million or 50.1% for the twelve months ended December 31, 2009 when compared to 2008 primarily due to lower market prices for power and a 14.6% decline in MWh sales. For the twelve months ended December 31, 2009, retained margins decreased $11.3 million when compared to the same period in 2008 due to the lower market power prices.

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

Years Ended December 31:	2010	2009	Increase (Decrease) Amount	Increase (Decrease) Percent
kWh sales:				
Retail:				
Residential	2,508,834	2,361,650	147,184	6.2 %
Commercial and industrial, small	2,295,537	2,251,399	44,138	2.0
Commercial and industrial, large	1,087,413	1,024,186	63,227	6.2
Sales to public authorities	1,542,389	1,482,448	59,941	4.0
Total retail sales	7,434,173	7,119,683	314,490	4.4
Wholesale:				
Sales for resale	53,637	56,931	(3,294)	(5.8)
Off-system sales	2,822,732	2,995,984	(173,252)	(5.8)
Total wholesale sales	2,876,369	3,052,915	(176,546)	(5.8)
Total kWh sales	10,310,542	10,172,598	137,944	1.4
Operating revenues:				
Non-fuel base revenues:				
Retail:				
Residential	$ 217,615	$ 195,798	$ 21,817	11.1 %
Commercial and industrial, small	188,390	175,328	13,062	7.5
Commercial and industrial, large	43,844	34,804	9,040	26.0
Sales to public authorities	86,460	77,370	9,090	11.7
Total retail non-fuel base revenues	536,309	483,300	53,009	11.0
Wholesale:				
Sales for resale	1,943	2,037	(94)	(4.6)
Total non-fuel base revenues	538,252	485,337	52,915	10.9
Fuel revenues:				
Recovered from customers during the period	170,588	196,081	(25,493)	(13.0) (1)
Under (over) collection of fuel	(35,408)	(66,608)	31,200	(46.8)
New Mexico fuel in base rates	71,876	69,026	2,850	4.1
Total fuel revenues	207,056	198,499	8,557	4.3
Off-system sales	105,317	116,064	(10,747)	(9.3)
Other	26,626	28,096	(1,470)	(5.2) (2)
Total operating revenues	$ 877,251	$ 827,996	$ 49,255	5.9
Average number of retail customers:				
Residential	331,869	326,002	5,867	1.8
Commercial and industrial, small	36,536	36,040	496	1.4
Commercial and industrial, large	49	49	0	0.0
Sales to public authorities	4,701	4,940	(239)	(4.8)
Total	373,155	367,031	6,124	1.7

(1) Excludes $34.8 million refunds in 2010 and refunds net of surcharges of $0.5 million in 2009 related to Texas deferred fuel revenues from prior periods.

(2) Represents revenues with no related kWh sales.

Years Ended December 31:	2009	2008	Increase (Decrease) Amount	Increase (Decrease) Percent
kWh sales:				
Retail:				
Residential	2,361,650	2,227,838	133,812	6.0 %
Commercial and industrial, small	2,251,399	2,255,585	(4,186)	(0.2)
Commercial and industrial, large	1,024,186	1,102,277	(78,091)	(7.1)
Sales to public authorities	1,482,448	1,448,654	33,794	2.3
Total retail sales	7,119,683	7,034,354	85,329	1.2
Wholesale:				
Sales for resale	56,931	50,148	6,783	13.5
Off-system sales	2,995,984	3,506,770	(510,786)	(14.6)
Total wholesale sales	3,052,915	3,556,918	(504,003)	(14.2)
Total kWh sales	10,172,598	10,591,272	(418,674)	(4.0)
Operating revenues:				
Non-fuel base revenues:				
Retail:				
Residential	$ 195,798	$ 184,800	$ 10,998	6.0 %
Commercial and industrial, small	175,328	174,593	735	0.4
Commercial and industrial, large	34,804	36,318	(1,514)	(4.2)
Sales to public authorities	77,370	74,427	2,943	4.0
Total retail non-fuel base revenues	483,300	470,138	13,162	2.8
Wholesale:				
Sales for resale	2,037	1,646	391	23.8
Total non-fuel base revenues	485,337	471,784	13,553	2.9
Fuel revenues:				
Recovered from customers during the period	196,081	198,292	(2,211)	(1.1) (1)
Under (over) collection of fuel	(66,608)	42,752	(109,360)	N/A
New Mexico fuel in base rates	69,026	68,631	395	0.6
Total fuel revenues	198,499	309,675	(111,176)	(35.9)
Off-system sales	116,064	232,500	(116,436)	(50.1)
Other	28,096	24,971	3,125	12.5 (2)
Total operating revenues	$ 827,996	$ 1,038,930	$ (210,934)	(20.3)
Average number of retail customers:				
Residential	326,002	320,323	5,679	1.8
Commercial and industrial, small	36,040	35,767	273	0.8
Commercial and industrial, large	49	52	(3)	(5.8)
Sales to public authorities	4,940	4,892	48	1.0
Total	367,031	361,034	5,997	1.7

(1) Excludes refunds net of fuel surcharges of $0.5 million in 2009 and a $26.0 million surcharge in 2008 related to Texas deferred fuel revenues from prior periods.

(2) 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 represents approximately 39% of our available net generating capacity and approximately 58% of our Company-generated energy for the twelve months ended December 31, 2010. Large fluctuations in the price of natural gas, which also is the primary factor influencing the price of purchased power, have had a significant impact on our cost of energy.

Energy expenses decreased $2.7 million or 1% for the twelve months ended December 31, 2010 compared to 2009 primarily due to decreased costs of purchased power of $16.7 million due to a 12% decrease in MWhs purchased and a 4% decrease in the average price of power purchased. This decrease was partially offset by (i) an increase of $9.6 million in natural gas costs due to a 21% increase in MWhs generated with natural gas partially offset by a 12% decrease in the average price of natural gas, and (ii) an increase of $6.2 million in the cost of nuclear fuel due to a 33% increase in the cost of nuclear fuel burned partially offset by a $3.3 million DOE settlement related to spent nuclear fuel. Total energy requirements increased 0.2 million MWhs in 2010 compared to 2009 due to increased retail sales.

Energy expenses decreased $205.9 million or 41% for the twelve months ended December 31, 2009 when compared to 2008 primarily due to (i) decreased natural gas costs of $106.4 million due to a 35% decrease in the average price of natural gas and an 11% decrease in MWhs generated with natural gas, and (ii) decreased costs of purchased power of $101.9 million due to a 41% decrease in the average price of power purchased and a 13% decrease in MWhs purchased. Total energy requirements decreased 0.5 million MWhs in 2009 compared to 2008 as a result of decreased off-system sales.

The table below details the sources and costs of energy for 2010, 2009 and 2008.

	2010			2009		
Fuel Type	Cost (in thousands)	MWh	Cost per MWh	Cost (in thousands)	MWh	Cost per MWh
Natural Gas	$ 153,568	2,890,110	$ 53.14	$ 143,943	2,385,632	$ 60.34
Coal	11,011	650,236	16.93	12,838	744,858	17.24
Nuclear	35,250 (a)	4,925,313	7.16	29,056	4,848,800	5.99
Total	199,829	8,465,659	23.60	185,837	7,979,290	23.29
Purchased power	91,916	2,420,869	37.97	108,603	2,745,500	39.56
Total energy	$ 291,745	10,886,528	26.80	$ 294,440	10,724,790	27.45

(a) Includes a DOE refund of $3.3 million recorded in 2010.

	2008		
Fuel Type	Cost (in thousands)	MWh	Cost per MWh
Natural Gas	$ 250,367	2,679,684	$ 93.43
Coal	13,520	720,951	18.75
Nuclear	25,929	4,622,840	5.61
Total	289,816	8,023,475	36.12
Purchased power	210,483	3,152,396	66.77
Total energy	$ 500,299	11,175,871	44.77

Other operations expense

Other operations expense increased $8.4 million or 3.9% in 2010 compared to 2009 primarily due to (i) increased customer accounts and service expense related to the transition to our new customer billing system and increased uncollectible customer accounts of $3.9 million, and (ii) increased administrative and general expense of $5.2 million due to increased pension and benefits expense reflecting changes in actuarial assumptions used to calculate expenses for our pension plans.

Other operations expense increased $15.4 million or 7.7% in 2009 compared to 2008 primarily due to (i) increased Palo Verde operations expense of $6.3 million, (ii) increased administrative and general expenses of $5.2 million due to increased accruals for employee incentive compensation and increased pension and benefits expenses reflecting a lower discount rate used to determine postretirement benefit costs, and (iii) increased operations expense of $1.9 million at our coal and gas-fired generating plants.

Maintenance expense

Maintenance expenses decreased $2.8 million or 4.7% in 2010 compared to 2009 due primarily to decreased maintenance expense at Palo Verde of $3.0 million as a result of decreased maintenance during refueling outages in 2010 compared to refueling outages in 2009.

Maintenance expense decreased $7.5 million or 11.2% in 2009 compared to 2008 due to (i) decreased maintenance expense at our gas-fired generating plants of $2.7 million as a result of the timing of planned maintenance, (ii) decreased maintenance expense at Palo Verde of $2.7 million, (iii) decreased maintenance at our general and administrative buildings of $1.1 million, and (iv) decreased maintenance of our distribution system of $1.0 million.

Depreciation and amortization expense

Depreciation and amortization expense increased $6.1 million or 8.1% in 2010 compared to 2009 primarily due to increased depreciable plant balances including the new customer information system, increased amortization of New Mexico rate case costs, and increased depreciation rates. Depreciation and amortization expense decreased $0.6 million in 2009 compared to 2008 primarily due to completing the amortization of certain fair value adjustments in December 2008 partially offset by increased depreciable plant balances.

Taxes other than income taxes

Taxes other than income taxes increased $4.5 million or 9.0% in 2010 compared to 2009 primarily due to increased revenue-related taxes and increased property taxes. Taxes other than income taxes increased $0.2 million in 2009 compared to 2008 primarily due to increased property tax in New Mexico and Texas and increased payroll taxes. These increases were partially offset by a decrease in revenue-related taxes.

Other income (deductions)

Other income (deductions) increased $3.5 million or 33% in 2010 compared to 2009 primarily as a result of (i) increased allowance for equity funds used during construction ("AEFUDC") of $1.5 million due to higher balances of construction work in progress in 2010, and (ii) increased investment and interest income primarily as a result of $2.2 million in impairment and net realized losses on investments in our Palo Verde decommissioning trusts in 2009 compared to $0.1 million impairment and net realized losses in 2010.

Other income (deductions) decreased $0.2 million in 2009 compared to 2008 primarily due to decreased miscellaneous non-operating income of $1.4 million partially offset by increased AEFUDC of $1.0 million as a result of higher balances of construction work in progress in 2009. In 2008, miscellaneous non-operating income included income from an increase in the cash surrender value of life insurance policies due to a 10-year interest rate adjustment and the settlement of a death benefit with no comparable activity in 2009. During 2009, we incurred impairments and realized losses on equity investments in our decommissioning trusts of $2.2 million compared to $2.9 million in 2008.

Interest charges (credits)

Interest charges (credits) decreased $2.0 million or 4.6% in 2010 compared to 2009 primarily due to (i) lower interest rates on pollution control bonds and (ii) increased allowance for borrowed funds used during construction ("ABFUDC") as a result of higher balances of construction work in progress in 2010. Two series of pollution control bonds were refunded in March 2009 at a fixed interest rate of 7.25% which was lower than the variable interest rates applied to these bonds before refunding.

Interest charges (credits) increased $2.7 million in 2009 compared to 2008 primarily due to a $4.8 million increase in interest related to the issuance of $150 million of 7.50% Senior Notes in June 2008, partially offset by a $2.1 million increase in ABFUDC.

Income tax expense

Income tax expense, before extraordinary item, increased by $18.0 million or 54.4% in 2010 compared to 2009 primarily due to an increase in pre-tax income and a one-time non-cash charge to tax expense related to the Patient Protection and Affordable Care Act ("PPACA") which was signed into law in March 2010. A major provision of the law is that, beginning in 2013, the income tax deductions for the cost of providing certain prescription drug coverage will be reduced by the amount of the Medicare Part D subsidies received. The Company was required to recognize the impacts of the tax law change at the time of enactment and recorded a one-time non-cash charge to income tax expense of approximately $4.8 million in the first quarter of 2010. Income tax expense for the twelve months ended December 31, 2009 compared to the same period in 2008, decreased $4.8 million reflecting lower pre-tax income.

Extraordinary Item

As a regulated electric utility, we prepare our financial statements in accordance with the FASB guidance for regulated operations. FASB guidance for regulated operations requires us to show certain items as assets or liabilities on our balance sheet when the regulator provides assurance that these items will be charged to and collected from our customers or refunded to our customers. In the final order for PUCT Docket No. 37690, we were allowed to include the previously expensed loss on reacquired debt associated with the refinancing of first mortgage bonds in 2005 in our calculation of the weighted cost of debt to be recovered from our customers. We recorded the impacts of the re-application of FASB guidance for regulated operations to our Texas jurisdiction in 2006 as an extraordinary item. In order to establish this regulatory asset, we recorded an extraordinary gain of $10.3 million, net of income tax expense of $5.8 million, in our 2010 statements of operations. This item was recorded as a regulatory asset during the quarter ended September 30, 2010 pursuant to the final order received from the PUCT and will be amortized over the remaining life of our 6% Senior Notes due in 2035.

New accounting standards

In December 2009, the FASB issued revised guidance related to financial reporting by enterprises involved with variable interest entities. This guidance became effective for reporting periods beginning after November 15, 2009. The guidance requires an enterprise to perform an analysis to determine whether the enterprise's variable interest or interests give it a controlling financial interest in a variable interest entity. We have performed the required analysis and have determined that we do not have any purchased power agreements or other arrangements that qualify as a variable interest entity.

Effective April 1, 2009, we adopted FASB guidance which establishes general standards of accounting and disclosure of events that occur after the balance sheet date but before financial statements are issued. In February 2010, we adopted an amendment to FASB guidance, removing the requirement for an SEC filer to disclose a date through which subsequent events have been evaluated. This new guidance changed our disclosures but does not impact our financial statements.

In January 2010, the FASB issued new guidance to improve disclosure requirements related to fair value measurements and disclosures. The new requirements include (i) disclosure of significant transfers in and out of Level 1 and Level 2 fair value measurements and the reasons for the transfers; and (ii) disclosure in the reconciliation for Level 3 fair value measurements of information about purchases, sales, issuances, and settlements on a gross basis. The new guidance also clarifies existing disclosures and requires (i) an entity to provide fair value measurement disclosures for each class of assets and liabilities and (ii) disclosures about inputs and valuation techniques. The provisions of this new guidance were adopted in the first quarter of 2010 except for the reconciliation for the Level 3 fair value measurements on a gross basis which will be adopted during the first quarter of 2011. During the twelve months ended December 31, 2010, there were no transfers in or out of Level 1 or Level 2 categories. This guidance requires additional disclosure on fair value measurements but does not impact our consolidated financial statements.

Inflation

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

We continue to maintain a strong capital structure which allows us to access financing from the capital markets at a reasonable cost. At December 31, 2010, our capital structure, including common stock, long-term debt, and the current portion of long-term debt and financing obligations, consisted of 48.7% common stock equity and 51.3% debt. At December 31, 2010, we had on hand $79.2 million in cash and cash equivalents, most of which was in funds invested in United States Treasury securities.

Our principal liquidity requirements in the near-term are expected to consist of capital expenditures to expand and support electric service obligations, expenditures for nuclear fuel inventory, interest payments on our indebtedness, and operating expenses including fuel costs, non-fuel operation and maintenance costs and taxes. In addition, we may repurchase common stock in the future.

Capital requirements and resources have been impacted by the timing of the recovery of fuel costs through fuel recovery mechanisms in Texas and New Mexico and our sales for resale customer. We recover actual fuel costs from customers through fuel adjustment mechanisms in Texas, New Mexico, and from our sales for resale customer. We record deferred fuel revenues for the under-recovery or over-recovery of fuel costs until they can be recovered from or refunded to customers. In Texas, fuel costs are recovered through a fixed fuel factor. Effective July 1, 2010, we can seek to revise our fixed fuel factor based upon our approved formula at least four months after our last revision except in the month of December.

During the twelve months ended December 31, 2010, we had net cash provided by operating activities of $239.4 million. This balance declined by $29.8 million compared to 2009 due primarily to a reduction in the collection of deferred fuel revenues in 2010. During the twelve months ended December 31, 2010, the Company had an over-recovery of deferred fuel revenues, net of refunds, of $1.0 million as compared to an over-recovery, including net surcharges, of $64.9 million during the twelve months ended December 31, 2009. At December 31, 2010, we had a net fuel over-recovery balance of $19.0 million, including $14.2 million in Texas and $4.8 million in New Mexico. The fuel over-recovery balance in New Mexico will be refunded through our fuel adjustment clause during 2011.

On February 18, 2011, the Company filed a petition with the PUCT which was assigned Docket No. 39159 to refund $11.8 million in fuel cost over-recoveries, including interest, for the period October 2010 through December 2010. In its filing, we requested the refund be made to customers in the single billing month of April 2011. This case is pending.

Capital Requirements. During the twelve months ended December 31, 2010, our capital requirements primarily consisted of expenditures for the construction and purchase of electric utility plant, purchases of nuclear fuel, and the repurchase of common stock. Projected utility construction expenditures will consist primarily of expanding and updating our transmission and distribution systems, adding new generation, and making capital improvements and replacements at Palo Verde and other generating facilities. We are constructing Newman Unit 5, a 288 MW gas-fired combined cycle combustion turbine generating unit, which is being completed in two phases at an estimated cost of approximately $230 million, including AFUDC. The first phase of Newman Unit 5 was completed in May 2009 and the second phase is currently expected to be completed before the summer of 2011. As of December 31, 2010, we had expended $209.7 million, including AFUDC, on Newman Unit 5, including $50.1 million during 2010. Estimated construction expenditures for 2011 are approximately $208.4 million and we expect cash from operations will continue to be a primary source of funds for these capital expenditures. See Part I, Item 1, "Business – Construction Program". Capital expenditures were $170.0 million in the twelve months ended December 31, 2010 compared to $210.0 million in the twelve months ended December 31, 2009.

We currently do not pay dividends on our common stock. Since 1999, we have returned cash to stockholders through a stock repurchase program pursuant to which we have bought approximately 22.6 million shares at an aggregate cost of $337.1 million, including commissions. Under our program, purchases can be made at open market prices or in private transactions and repurchased shares are available for issuance under employee benefit and stock incentive plans, or may be retired. On February 19, 2010, the Board of Directors authorized a repurchase of up to two million shares of the Company's outstanding common stock ("2010 Plan"). During the twelve months ended December 31, 2010, we repurchased 1,524,711 shares of common stock in the open market at an aggregate cost of $33.7 million under both a previously authorized program and under the 2010 Plan. As of December 31, 2010, 676,271 shares remain eligible for purchase under the 2010 Plan. Our Board is currently analyzing the relative advantages of providing our stockholders a cash return on their investment through a cash dividend instead of, or in addition to, our current program.

Our cash requirements for federal and state income taxes vary from year to year based on taxable income, which is influenced by the timing of revenues and expenses recognized for income tax purposes. Due to accelerated tax deductions, tax payments are expected to be minimal in 2011.

We continually evaluate our funding requirements related to our retirement plans, other postretirement benefit plans, and decommissioning trust funds. We contributed $8.5 million and $11.8 million to our retirement plans during the twelve months ended December 31, 2010 and 2009, respectively. We also contributed $4.6 million and $3.4 million to our other postretirement benefit plan during the twelve months ended December 31, 2010 and 2009, respectively. We contributed $8.2 million and $7.9 million to our decommissioning trust funds for 2010 and 2009, respectively. We are in compliance with the funding requirements of the federal government for our benefit plans and decommissioning trust. We will continue to review our funding for these plans in order to meet our future obligations.

Capital Resources. On August 17, 2010, RGRT completed the sale of $110 million aggregate principal amount of senior notes. We guarantee RGRT's payment of principal and interest on the senior notes. RGRT is the trust through which we finance our portion of nuclear fuel for Palo Verde, and its assets, liabilities and operations are consolidated in the Company's financial statements. The proceeds from the sale of the senior notes were used by RGRT to repay amounts borrowed under the then existing revolving credit facility and will enable future nuclear fuel financing requirements of RGRT to be met with a combination of the senior notes and amounts borrowed under the revolving credit facility.

On September 23, 2010, the Company, along with RGRT, entered into a new credit agreement for a $200 million RCF. The RCF has a term of four years, and we may request that the facility be increased up to $300 million during the term of the facility, subject to lender approval. The terms of the agreement provide that amounts we borrow under the facility may be used for working capital and general corporate purposes. Any amounts borrowed by RGRT may be used to finance the acquisition and processing of nuclear fuel. We guarantee the amounts borrowed by RGRT. This RCF replaces the $200 million revolving credit facility that was due to expire on April 11, 2011. The total amount outstanding for nuclear fuel by RGRT was $114.7 million at December 31, 2010 of which $4.7 million was borrowed under this new RCF and $110.0 million was borrowed through the senior notes discussed above. Borrowings by RGRT for nuclear fuel were $107.0 million as of December 31, 2009, including accrued interest and fees, all of which were borrowed under the revolving credit facility then in effect. Interest costs on borrowings to finance nuclear fuel are accumulated by RGRT and charged to the Company as fuel is consumed and is recovered by the Company from customers through fuel recovery charges. No borrowings were outstanding at December 31, 2010 under the RCF for working capital or general corporate purposes.

At December 31, 2010, we had $195.3 million of unused credit available on our new RCF discussed above. The combination of the issuance of senior notes by RGRT and the refinancing of the RCF provided additional liquidity to the Company. We expect to have sufficient liquidity to finance construction expenditures and other capital requirements through 2011. In addition, we may seek to issue debt in the capital markets to finance capital requirements.

Contractual Obligations. Our contractual obligations as of December 31, 2010 are as follows (in thousands):

	Payments due by period				
	Total	2011	2012 and 2013	2014 and 2015	2016 and Beyond
Long-Term Debt (including interest):					
Senior notes (1)	$ 1,442,094	$ 35,250	$ 70,500	$ 70,500	$ 1,265,844
Pollution control bonds (2)	491,926	11,469	54,351	20,274	405,832
RGRT Senior notes (3)	149,183	5,054	10,107	24,901	109,121
Financing Obligations (including interest):					
Revolving credit facility (4)	4,827	4,827	0	0	0
Purchase Obligations:					
Power contracts	8,257	4,033	3,072	1,152	0
Fuel contracts:					
Coal (5)	50,498	9,161	18,322	18,322	4,693
Gas (5)	348,991	42,603	73,433	72,742	160,213
Nuclear fuel (6)	137,919	18,799	24,087	33,184	61,849
Retirement Plans and Other Postretirement benefits (7)	4,100	4,100	0	0	0
Decommissioning trust funds (8)	229,082	8,531	19,212	21,596	179,743
Operating leases (9)	12,618	1,013	1,816	1,642	8,147
Total	$ 2,879,495	$ 144,840	$ 274,900	$ 264,313	$ 2,195,442

(1) We have two issuances of Senior Notes. In May 2005, we issued $400.0 million aggregate principal amount of 6% Senior Notes due May 15, 2035. In June 2008, we issued $150.0 million aggregate principal amount of 7.5% Senior Notes due March 15, 2038.

(2) We have four series of pollution control bonds which are scheduled for remarketing and/or mandatory tender, one in 2012 and the other three in 2040.

(3) In 2010, the Company and RGRT entered into a Note Purchase Agreement for $110 million aggregate principal amount of senior notes consisting of (a) $15 million aggregate principal amount of 3.67% RGRT Senior Notes, Series A, due August 15, 2015, (b) $50 million aggregate principal amount of 4.47% RGRT Senior Notes, Series B, due August 15, 2017, and (c) $45 million aggregate principal amount of 5.04% RGRT Senior Notes, Series C, due August 15, 2020.

(4) This reflects obligations outstanding under the $200 million RCF used for, among other things, working capital and general corporate purposes. Amounts borrowed by RGRT may be used, among other things, to finance nuclear fuel. The balance includes interest based on actual interest rates at the end of 2010.

(5) Amount is based on the minimum volumes per the contract and market and/or contract price at the end of 2010. Gas obligation includes a gas storage contract and a gas transportation contract.

(6) Some of the nuclear fuel contracts are based on a fixed price, adjusted for an index. The index used is the index at the end of 2010.

(7) These obligations include our minimum contractual funding requirements for the non-qualified retirement income plan and the other postretirement benefits for 2011. We have no minimum contractual funding requirement related to our retirement income plan for 2011. However, we may decide to fund at higher levels and expect to contribute $13.9 million and $2.2 million to our retirement plans and postretirement benefit plan, respectively, in 2011, as disclosed in Part II, Item 8, Notes to Consolidated Financial Statements, Note L, Employee Benefits. Minimum contractual funding requirements for 2012 and beyond are not included due to the uncertainty of interest rates and the related return on assets.

(8) These obligations represent funding requirements under the ANPP Participation Agreement based on the current rate of return on investments. Decommissioning trust funding could be adjusted if the NRC approves the application to extend the Palo Verde licenses for 20 years.

(9) In June 2008, we entered into an agreement to lease land in El Paso adjacent to the Newman Power Station under a lease which expires in June 2033 with a renewal option of 25 years. In addition, we lease certain warehouse facilities in El Paso under a lease which expires in December 2014. We also have several other leases for office and parking facilities which expire within the next five years.

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, except for our revolving credit facility which is based on floating rates.

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 PUCT and NMPRC rules which establish energy cost recovery clauses. Under these rules, actual 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 fair 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 $85.9 million and $74.6 million as of December 31, 2010 and 2009, respectively. A hypothetical 10% increase in interest rates would reduce the fair values of these funds by $1.3 million and $1.1 million based on their fair values at December 31, 2010 and 2009, respectively.

Equity Price Risk

Our decommissioning trust funds include marketable equity securities of approximately $68.0 million and $60.8 million at December 31, 2010 and 2009, respectively. A hypothetical 20% decrease in equity prices would reduce the fair values of these funds by $13.6 million and $12.2 million based on their fair values at December 31, 2010 and 2009, respectively. Declines in market prices could require that additional amounts be contributed to our decommissioning trusts to maintain minimum funding requirements. We will not have a requirement to expend monies held in trust before 2024 or a later period when we begin to decommission Palo Verde.

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 PUCT 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. We also enter into 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, 2011, 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 FASB guidance for accounting for derivative instruments and hedging activities and are not recorded at their fair value in our financial statements. Because of the operation of the PUCT 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, 2010. In making this assessment, the Company's management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in Internal Control-Integrated Framework.

Based on its assessment, management believes that, as of December 31, 2010, 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 57 of this report.

Item 8. Financial Statements and Supplementary Data

INDEX TO FINANCIAL STATEMENTS

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, 2010 and 2009, 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, 2010. We also have audited El Paso Electric Company's internal control over financial reporting as of December 31, 2010, 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.

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, 2010 and 2009, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2010, in conformity with U.S. generally accepted accounting principles. Also in our opinion, El Paso Electric Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

/s/ KPMG LLP

Houston, Texas
February 25, 2011

EL PASO ELECTRIC COMPANY AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS

ASSETS (In thousands)	December 31, 2010	December 31, 2009
Utility plant:		
Electric plant in service	$ 2,522,862	$ 2,392,850
Less accumulated depreciation and amortization	(1,047,498)	(981,314)
Net plant in service	1,475,364	1,411,536
Construction work in progress	285,086	244,166
Nuclear fuel; includes fuel in process of $47,746 and $50,929, respectively	150,774	135,021
Less accumulated amortization	(45,471)	(34,737)
Net nuclear fuel	105,303	100,284
Net utility plant	1,865,753	1,755,986
Current assets:		
Cash and cash equivalents	79,184	91,790
Accounts receivable, principally trade, net of allowance for doubtful accounts of $2,885 and $1,191, respectively	71,685	70,382
Accumulated deferred income taxes	25,818	20,445
Inventories, at cost	36,132	37,935
Income taxes receivable	12,656	24,162
Prepayments and other	4,543	4,837
Total current assets	230,018	249,551
Deferred charges and other assets:		
Decommissioning trust funds	153,878	135,372
Regulatory assets	88,557	60,708
Other	26,560	24,535
Total deferred charges and other assets	268,995	220,615
Total assets	$ 2,364,766	$ 2,226,152

See accompanying notes to consolidated financial statements.

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

CAPITALIZATION AND LIABILITIES
(In thousands except for share data)

	December 31, 2010	December 31, 2009
Capitalization:		
Common stock, stated value $1 per share, 100,000,000 shares authorized, 65,121,689 and 64,946,729 shares issued, and 143,371 and 147,427 restricted shares, respectively	$ 65,265	$ 65,094
Capital in excess of stated value	305,068	301,180
Retained earnings	810,858	710,255
Accumulated other comprehensive income (loss), net of tax	(33,177)	(49,887)
	1,148,014	1,026,642
Treasury stock, 22,693,995 and 21,169,284 shares, respectively, at cost	(337,639)	(303,913)
Common stock equity	810,375	722,729
Long-term debt, net of current portion	849,745	739,697
Financing obligations, net of current portion	0	65,278
Total capitalization	1,660,120	1,527,704
Current liabilities:		
Current portion of long-term debt and financing obligations	4,704	41,720
Accounts payable, principally trade	41,795	54,702
Taxes accrued	29,172	22,157
Interest accrued	12,099	10,283
Overcollection of fuel revenues	18,976	18,018
Other	24,207	24,896
Total current liabilities	130,953	171,776
Deferred credits and other liabilities:		
Accumulated deferred income taxes	286,730	233,424
Accrued pension liability	93,471	80,940
Asset retirement obligation	92,911	85,358
Accrued postretirement benefit liability	61,594	88,919
Regulatory liabilities	14,489	14,127
Other	24,498	23,904
Total deferred credits and other liabilities	573,693	526,672
Commitments and contingencies		
Total capitalization and liabilities	$ 2,364,766	$ 2,226,152

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, 2010	2009	2008
Operating revenues	$ 877,251	$ 827,996	$ 1,038,930
Energy expenses:			
Fuel	199,829	185,837	289,816
Purchased and interchanged power	91,916	108,603	210,483
	291,745	294,440	500,299
Operating revenues net of energy expenses	585,506	533,556	538,631
Other operating expenses:			
Other operations	224,221	215,841	200,408
Maintenance	56,823	59,606	67,110
Depreciation and amortization	81,011	74,946	75,571
Taxes other than income taxes	54,489	49,998	49,806
	416,544	400,391	392,895
Operating income	168,962	133,165	145,736
Other income (deductions):			
Allowance for equity funds used during construction	10,816	9,311	8,279
Investment and interest income, net	5,315	3,813	3,798
Miscellaneous non-operating income	1,368	1,107	2,477
Miscellaneous non-operating deductions	(3,206)	(3,483)	(3,619)
	14,293	10,748	10,935
Interest charges (credits):			
Interest on long-term debt and financing obligations	50,826	50,512	47,605
Other interest	254	396	1,208
Capitalized interest	(2,487)	(943)	(3,620)
Allowance for borrowed funds used during construction	(6,671)	(6,029)	(3,973)
	41,922	43,936	41,220
Income before income taxes and extraordinary item	141,333	99,977	115,451
Income tax expense	51,016	33,044	37,830
Income before extraordinary item	90,317	66,933	77,621
Extraordinary gain related to Texas regulatory assets, net of tax	10,286	0	0
Net income	$ 100,603	$ 66,933	$ 77,621
Basic earnings per share:			
Income before extraordinary item	$ 2.08	$ 1.50	$ 1.73
Extraordinary gain related to Texas regulatory assets, net of tax	0.24	0.00	0.00
Net income	$ 2.32	$ 1.50	$ 1.73
Diluted earnings per share:			
Income before extraordinary item	$ 2.07	$ 1.50	$ 1.72
Extraordinary gain related to Texas regulatory assets, net of tax	0.24	0.00	0.00
Net income	$ 2.31	$ 1.50	$ 1.72
Weighted average number of shares outstanding	43,129,735	44,524,146	44,777,765
Weighted average number of shares and dilutive potential shares outstanding	43,294,419	44,595,067	44,930,109

See accompanying notes to consolidated financial statements.

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

	Years Ended December 31, 2010	2009	2008
Net income	$ 100,603	$ 66,933	$ 77,621
Other comprehensive income (loss):			
Unrecognized pension and postretirement benefit costs:			
Net loss arising during period	(9,874)	(48,580)	(30,587)
Prior service benefit	26,605	0	0
Reclassification adjustments included in net income for amortization of:			
Prior service cost	(2,754)	(2,754)	(2,754)
Net (gain) loss	3,374	1,625	(152)
Net unrealized gains (losses) on marketable securities:			
Net holding gains (losses) arising during period	6,665	12,816	(29,779)
Reclassification adjustments for net losses included in net income	122	2,218	2,876
Net gains on cash flow hedges:			
Reclassification adjustment for interest expense included in net income	338	317	297
Total other comprehensive income (loss) before income taxes	24,476	(34,358)	(60,099)
Income tax benefit (expense) related to items of other comprehensive income (loss):			
Unrecognized pension and postretirement benefit costs	(6,287)	16,957	11,922
Net unrealized gains (losses) on marketable securities	(1,357)	(3,007)	5,381
Losses on cash flow hedges	(122)	(115)	(108)
Total income tax benefit (expense)	(7,766)	13,835	17,195
Other comprehensive income (loss), net of tax	16,710	(20,523)	(42,904)
Comprehensive income	$ 117,313	$ 46,410	$ 34,717

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	Retained Earnings	Accumulated Other Comprehensive Income (Loss), Net of Tax	Treasury Stock		Total Common Stock Equity
	Shares	Amount				Shares	Amount	
Balances at December 31, 2007	64,519,925	$ 64,520	$ 292,614	$ 565,701	$ 13,540	19,370,266	$ (269,916)	$ 666,459
Restricted common stock grants and deferred compensation	117,550	118	1,328					1,446
Performance share awards vested	41,958	42	715					757
Stock awards withheld for taxes	(17,931)	(18)	(413)					(431)
Forfeitures and lapsed restricted common stock	(36,850)	(37)						(37)
Deferred taxes on stock incentive plan			43					43
Stock options exercised	108,000	108	1,059					1,167
Net income				77,621				77,621
Other comprehensive loss					(42,904)			(42,904)
Treasury stock acquired, at cost						478,634	(9,892)	(9,892)
Balances at December 31, 2008	64,732,652	64,733	295,346	643,322	(29,364)	19,848,900	(279,808)	694,229
Restricted common stock grants and deferred compensation	114,703	115	2,162					2,277
Stock awards withheld for taxes	(8,249)	(8)	(157)					(165)
Forfeitures and lapsed restricted common stock	(12,850)	(13)						(13)
Deferred taxes on stock incentive plan			328					328
Stock options exercised	267,900	267	3,501					3,768
Net income				66,933				66,933
Other comprehensive loss					(20,523)			(20,523)
Treasury stock acquired, at cost						1,320,384	(24,105)	(24,105)
Balances at December 31, 2009	65,094,156	65,094	301,180	710,255	(49,887)	21,169,284	(303,913)	722,729
Restricted common stock grants and deferred compensation	112,891	113	2,302					2,415
Performance share awards vested	9,525	10	653					663
Stock awards withheld for taxes	(10,261)	(11)	(236)					(247)
Forfeitures and lapsed restricted common stock	(37,993)	(38)	(463)					(501)
Deferred taxes on stock incentive plan			350					350
Stock options exercised	96,742	97	1,282					1,379
Net income				100,603				100,603
Other comprehensive income					16,710			16,710
Treasury stock acquired, at cost						1,524,711	(33,726)	(33,726)
Balances at December 31, 2010	65,265,060	$ 65,265	$ 305,068	$ 810,858	$ (33,177)	22,693,995	$ (337,639)	$ 810,375

See accompanying notes to consolidated financial statements.

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

	Years Ended December 31,		
	2010	**2009**	**2008**
Cash Flows From Operating Activities:			
Net income	$ 100,603	$ 66,933	$ 77,621
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization of electric plant in service	81,011	74,946	75,571
Amortization of nuclear fuel	31,316	22,305	19,705
Extraordinary gain related to Texas regulatory assets, net of tax	(10,286)	0	0
Deferred income taxes, net	27,456	40,846	16,646
Allowance for equity funds used during construction	(10,816)	(9,311)	(8,279)
Other amortization and accretion	16,740	14,440	13,784
Other operating activities	(881)	1,154	8,572
Change in:			
Accounts receivable	(1,303)	26,125	(11,929)
Inventories	1,143	2,135	(4,717)
Net overcollection (undercollection) of fuel revenues	958	64,875	(19,161)
Prepayments and other	(544)	(790)	(570)
Accounts payable	(9,634)	(1,988)	(4,306)
Taxes accrued	18,523	(17,704)	16,875
Interest accrued	1,816	2,764	3,172
Other current liabilities	(689)	750	1,248
Deferred charges and credits	(6,063)	(18,370)	(14,499)
Net cash provided by operating activities	239,350	269,110	169,733
Cash Flows From Investing Activities:			
Cash additions to utility property, plant and equipment	(169,966)	(209,974)	(198,711)
Cash additions to nuclear fuel	(34,277)	(34,904)	(25,767)
Capitalized interest and AFUDC:			
Utility property, plant and equipment	(17,487)	(15,340)	(12,252)
Nuclear fuel	(2,487)	(943)	(3,620)
Allowance for equity funds used during construction	10,816	9,311	8,279
Decommissioning trust funds:			
Purchases, including funding of $8.2 million, $7.9 million and $7.2 million, respectively	(73,192)	(90,118)	(67,169)
Sales and maturities	61,656	79,935	53,447
Proceeds from sale of investments in debt securities	0	0	16,000
Other investing activities	286	1,695	(1,638)
Net cash used for investing activities	(224,651)	(260,338)	(231,431)
Cash Flows From Financing Activities:			
Proceeds from exercise of stock options	1,379	3,768	1,167
Repurchases of common stock	(33,726)	(24,105)	(9,892)
Proceeds from issuance of long-term debt	110,000	0	148,719
Financing obligations:			
Proceeds	37,628	186,471	73,179
Payments	(139,922)	(173,126)	(62,541)
Excess tax benefits from long-term incentive plans	350	328	382
Other financing activities	(3,014)	(1,960)	(2,650)
Net cash provided by (used for) financing activities	(27,305)	(8,624)	148,364
Net increase (decrease) in cash and cash equivalents	(12,606)	148	86,666
Cash and cash equivalents at beginning of period	91,790	91,642	4,976
Cash and cash equivalents at end of period	$ 79,184	$ 91,790	$ 91,642

See accompanying notes to consolidated financial statements.

INDEX TO NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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 a full requirements wholesale customer in Texas.

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 discontinued these activities in 2002. 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 FASB Guidance for Regulated Operations. Regulated electric utilities typically prepare their financial statements in accordance with the Financial Accounting Standards Board ("FASB") guidance for regulated operations. FASB guidance for regulated operations requires the Company to include an allowance for equity and borrowed funds used during construction ("AEFUDC" and "ABFUDC") as a cost of construction of electric plant in service. AEFUDC is recognized as income and ABFUDC is shown as capitalized interest charges in the Company's statement of operations. FASB guidance for regulated operations also requires the Company to show certain recoverable costs 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) or will be credited or refunded to the utility's customers. The resulting regulatory assets or liabilities are amortized in subsequent periods based upon the respective amortization periods reflected in a utility's regulated rates. See Note C. The Company applies FASB guidance for regulated operations for all three of the jurisdictions in which it operates.

Extraordinary item. As discussed in the previous paragraph, FASB guidance for regulated operations requires the Company to show certain items as assets or liabilities on its balance sheet when the regulator provides assurance that these items will be charged to and collected from customers or refunded to customers. In the final order for Public Utility Commission of Texas ("PUCT") Docket No. 37690, the Company was allowed to include the previously expensed loss on reacquired debt associated with the refinancing of first mortgage bonds in 2005 in its calculation of the weighted cost of debt to be recovered from customers. The Company recorded the impacts of the re-application of FASB guidance for regulated operations to its Texas jurisdiction in 2006 as an extraordinary item. In order to establish this regulatory asset, the Company recorded an extraordinary gain of $10.3 million, net of income tax expense of $5.8 million, in its 2010 statements of operations. This item was recorded as a regulatory asset during the quarter ended September 30, 2010 pursuant to the final order received from the PUCT and will be amortized over the remaining life of the Company's 6% Senior Notes due in 2035.

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 FASB guidance for reporting comprehensive income.

Utility Plant. Utility plant is generally reported at cost. The cost of renewals and betterments are capitalized and the costs of repairs and minor replacements are charged to the appropriate operating expense accounts. Depreciation is provided on a straight-line basis over the estimated remaining lives of the assets (ranging in average from 3 to 48 years). The average composite depreciation rate utilized in 2010, 2009, and 2008 was 3.21%, 3.22%, and 3.25%, respectively. When property subject to composite depreciation is retired or otherwise disposed of in the normal course of business, its 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 D.

Impairment of Long-Lived Assets. Long-lived assets 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 capitalizes interest to nuclear fuel in process in accordance with the FERC Uniform System of Accounts as provided for in FASB guidance. 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 used for the first six months of 2010 was 9.01% and 8.47% thereafter. The AFUDC rates utilized in 2009 and 2008 were 8.94% and 8.57%, respectively.

Asset Retirement Obligation. FASB guidance 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 FASB guidance 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 and legal obligations to perform an asset retirement activity even if the timing and/or settlement are conditioned on a future event that may or may not be within the control of an entity. See Note E. Under FASB guidance, 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).

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

Investments in Debt Securities. In 2007, the Company invested excess cash in auction rate securities with contract maturity dates that extended beyond three months. These securities have interest rates that reset frequently, and historically had provided a liquid market to sell the securities to meet cash requirements. These securities were and still are classified as trading securities by the Company. The auction rate securities had successful auctions through January 2008. However, since February 13, 2008, auctions for $4.0 million of these investments have not been successful, resulting in the inability to liquidate these investments. These investments continue to pay interest. The Company reclassified them to deferred charges and other assets as of March 31, 2008 and has adjusted the carrying amount to fair value. See Note N.

Investments. The Company's marketable securities, included in decommissioning trust funds in the balance sheets, are reported at fair value and consist of cash, 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 (loss) 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 N.

Derivative Accounting. Accounting for derivative instruments and hedging activities 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 N.

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 billed under base rates and a fixed fuel factor approved by the PUCT. The Company's New Mexico retail customers and its sales for resale customer are billed under base rates and a fuel adjustment clause which is adjusted monthly, as approved by the New Mexico Public Regulation Commission ("NMPRC") and the FERC. The Company's recovery of energy expenses 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 customers is reflected as over/undercollection of fuel revenues in the consolidated balance sheets. See Note B.

Revenues. Revenues related to the sale of electricity are generally recorded when service is rendered or electricity is delivered to customers. The billing of electricity sales to retail customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. Unbilled revenues are estimated based on monthly generation volumes and by applying an average revenue/kWh to the number of estimated kWhs delivered but not billed. Accounts receivable included accrued unbilled revenues of $16.6 million and $18.2 million at December 31, 2010 and 2009, respectively. The Company presents revenues net of sales taxes in its consolidated statements of operations.

Allowance for Doubtful Accounts. The allowance for doubtful accounts represents the Company's estimate of existing accounts receivable that will ultimately be uncollectible. The allowance is calculated by applying estimated write-off factors to various classes of outstanding receivables. The write-off factors used to estimate uncollectible accounts are based upon consideration of both historical collections experience and management's best estimate of future collections success given the existing collections environment. Additions, deductions and balances for allowance for doubtful accounts for 2010, 2009 and 2008 are as follows (in thousands):

	2010	2009	2008
Balance at beginning of year	$ 1,191	$ 3,123	$ 2,873
Additions:			
Charged to costs and expense	4,756	3,289	3,328
Recovery of previous write-offs	852	1,316	1,184
Uncollectible receivables written off	3,914	6,537	4,262
Balance at end of year	$ 2,885	$ 1,191	$ 3,123

Income Taxes. The Company accounts for federal and state income taxes under the asset and liability method of accounting for income taxes. 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 guidance for uncertainty in income taxes. See Note I.

Earnings per Share. The Company's restricted stock awards are participating securities and earnings per share must be calculated using the two-class method in both the basic and diluted earnings per share calculations. For the basic earnings per share calculation, net income is allocated to restricted stock awards and to the weighted average number of shares outstanding. The net income allocated to the weighted average number of shares outstanding is then divided by the weighted average number of shares outstanding to derive the basic earnings per share. For the diluted earnings per share, net income is allocated to restricted stock awards and to the weighted average number of shares and dilutive potential shares outstanding. The Company's dilutive potential shares outstanding amount is calculated using the treasury stock method for the unvested performance shares and outstanding stock options. Net income allocated to the weighted average number of shares and dilutive potential shares is then divided by the weighted average number of shares and dilutive potential shares outstanding to derive the diluted earnings per share. See Note F.

Stock-Based Compensation. The Company has a stock-based long-term incentive plan. The Company is required under FASB guidance 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. Such costs are recognized over the period during which an employee is required to provide service in exchange for the award (the "requisite service period") which typically is the vesting period. Compensation cost is not recognized for anticipated forfeitures prior to vesting of equity instruments. See Note F.

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

Reclassification. Certain amounts in the consolidated financial statements for 2009 and 2008 have been reclassified to conform with the 2010 presentation.

Other New Accounting Standards. In December 2009, the FASB issued revised guidance related to financial reporting by enterprises involved with variable interest entities. This guidance became effective for reporting periods beginning after November 15, 2009. The guidance requires an enterprise to perform an analysis to determine whether the enterprise's variable interest or interests give it a controlling financial interest in a variable interest entity. The Company has performed the required analysis and has determined that the Company does not have any purchased power agreements or other arrangements that qualify as a variable interest entity.

Effective April 1, 2009, the Company adopted FASB guidance which establishes general standards of accounting and disclosure of events that occur after the balance sheet date but before financial statements are issued. In February 2010, The Company adopted an amendment to FASB guidance, removing the requirement for a Securities and Exchange Commission filer to disclose a date through which subsequent events have been evaluated. This new guidance changed the Company's disclosures but does not impact the Company's financial statements.

In January 2010, the FASB issued new guidance to improve disclosure requirements related to fair value measurements and disclosures. The new requirements include (i) disclosure of significant transfers in and out of Level 1 and Level 2 fair value measurements and the reasons for the transfers; and (ii) disclosure in the reconciliation for Level 3 fair value measurements of information about purchases, sales, issuances, and settlements on a gross basis. The new guidance also clarifies existing disclosures and requires (i) an entity to provide fair value measurement disclosures for each class of assets and liabilities and (ii) disclosures about inputs and valuation techniques. The provisions of this new guidance were adopted in the first quarter of 2010 except for the reconciliation for the Level 3 fair value measurements on a gross basis which will be adopted during the first quarter of 2011. During the twelve months ended December 31, 2010, there were no transfers in or out of Level 1 or Level 2 categories. This guidance requires additional disclosure on fair value measurements but does not impact the Company's consolidated financial statements.

B. Regulation

General

The rates and services of the Company are regulated by incorporated municipalities in Texas, the PUCT, the NMPRC, and the FERC. The PUCT 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 and compliance with federally-mandated reliability standards. The decisions of the PUCT, NMPRC and the FERC are subject to judicial review.

Texas Regulatory Matters

Texas Freeze Period. In 2005, the Company entered into agreements ("Texas Rate Agreements") with El Paso, PUCT staff and other parties in Texas that provided for most retail base rates to remain at their existing level through June 30, 2010. During the rate freeze period, if the Company's return on equity fell below the bottom of a defined range, the Company had the right to initiate a rate case and seek an adjustment to base rates. If the Company's return on equity exceeded the top of the range, the Company would refund an amount equal to 50% of the Texas jurisdictional pretax return in excess of the ceiling. The Company's return on equity fell within the then prevailing range during the last reporting period. Also pursuant to the Texas Rate Agreements, the Company agreed to share with its Texas customers 25% of off-system sales margins increasing to 90% after June 30, 2010.

2009 Texas Retail Rate Case. On December 9, 2009, the Company filed an application with the PUCT for authority to change rates, to reconcile fuel costs, to establish formula-based fuel factors, and to establish an energy efficiency cost-recovery factor. This case was assigned PUCT Docket No. 37690. The filing included a base rate increase which was based upon an adjusted test year ended June 30, 2009.

On July 30, 2010, the PUCT approved a settlement in the 2009 Texas retail rate case in PUCT Docket No. 37690. The settlement calls for an annual non-fuel base rate increase of $17.15 million effective for usage beginning July 1, 2010. This increase was partially offset by the provision that, consistent with a prior rate agreement, effective July 1, 2010, the Company shares 90% of off-system sales margins with customers and retains 10% of such margins. Previously, the Company retained 75% of off-system sales margins. Interim rates went into effect July 1, 2010 pending final approval by the PUCT. All additions to electric plant in service since June 30, 1993 through June 30, 2009 were deemed to be reasonable and necessary with the exception of one small addition. The Company's new customer information system completed in April 2010 was also included in base rates with a ten-year amortization. The settlement provides for the reconciliation of fuel costs incurred through June 30, 2009 except for the recovery of final Four Corners' coal mine reclamation costs. The fuel reconciliation (Docket No. 38361) was bifurcated from the rate case to allow for litigation of the final coal mine reclamation costs. The PUCT also approved the use of a formula-based fuel factor which provides for more timely recovery of fuel costs. The PUCT approved a $19.7 million or 11% reduction in the Company's fixed fuel factor as the initial rate under the approved fuel factor formula. The PUCT also approved an energy efficiency cost-recovery factor that includes the recovery of deferred energy efficiency costs over a three-year period.

Fuel Reconciliation Case (Severed from 2009 Rate Case). Pursuant to the stipulation in Docket No. 37690, the fuel reconciliation component of the rate case was severed and a separate docket, PUCT Docket No. 38361, was established to address one fuel reconciliation issue not settled by the parties. That single issue was a determination of the proper amount of the Four Corners' coal mine final reclamation costs to be recovered from the Company's Texas retail customers. The hearing on the merits of the case was held on August 11, 2010. On November 23, 2010 the Administrative Law Judge issued the Proposal for Decision which approved the Company's request. The PUCT issued a final order approving the Proposal for Decision on January 27, 2011.

Fuel and Purchased Power Costs. The Company's actual fuel costs, including purchased power energy costs, are recoverable from its customers. The PUCT has adopted a fuel cost recovery rule ("Texas Fuel Rule") that allows the Company to seek periodic adjustments to its fixed fuel factor. The Company received approval on July 30, 2010 in PUCT Docket No. 37690 (discussed above), to implement a formula to determine its fuel factor. The Company can seek to revise its fixed fuel factor based upon the approved formula at least four months after its last revision except in the month of December. The Texas Fuel Rule requires the Company to request to refund fuel costs in any month when the over-recovery balance exceeds a threshold material amount and it expects fuel costs to continue to be materially over-recovered. The Texas Fuel Rule also permits the Company to seek to surcharge fuel under-recoveries in any month the balance exceeds a threshold material amount and it expects fuel cost recovery to continue to be materially under-recovered. Fuel over and under recoveries are considered material when they exceed 4% of the previous twelve months' fuel costs. All such fuel revenue and expense activities are subject to periodic final review by the PUCT in fuel reconciliation proceedings.

On December 17, 2009, the Company filed a petition with the PUCT in Docket No. 37788 to refund $11.8 million in fuel cost over-recoveries, including interest, for the period September through November 2009. On January 20, 2010, a stipulation was filed that resolved all of the issues in this proceeding. The stipulation provided for the Company to implement a fuel refund for the net over-recovery of $11.8 million, including interest, in the month of February 2010. On January 21, 2010, the Administrative Law Judge assigned to the docket issued an order approving the implementation of interim rates to allow the requested refund to be made. The PUCT issued a final order on February 11, 2010 approving the stipulation.

On November 23, 2010, the Company filed a Petition to Revise its Fixed Fuel Factor pursuant to the Fuel Factor Formula authorized in PUCT Docket No. 37690 for determining the Company's fuel factor. The Company's request was to decrease its fixed fuel factor by 14.7%. On December 2, 2010, the State Office of Administrative Hearings ("SOAH") Administrative Law Judge issued Order No. 1, establishing interim rates as requested, as well as a deadline of December 3, 2010, for the purpose of requesting a hearing, and absent such a request, implementation of the revised fuel factor would become final by its own terms and without further PUCT order. No request was received; therefore, the revised fuel factor became final. On January 6, 2011, the SOAH Administrative Law Judge dismissed the proceeding from the SOAH docket, the case was dismissed from the PUCT's docket on that same date, and the case was closed.

On October 20, 2010, the Company filed a petition with the PUCT which was assigned Docket No. 38802 to refund $12.8 million in fuel cost over-recoveries, including interest, for the period April 2010 through September 2010. In its filing, the Company requested the refund be made to customers in the single billing month of December 2010. On November 22, 2010, a stipulation was filed that resolved all issues in this case and requested that an order be issued that would allow the interim refund in December 2010 consistent with the Company's filing. The Administrative Law Judge issued an order approving the implementation of interim rates to allow the requested refund to be made in December. On December 16, 2010, the PUCT issued a final order approving the stipulation.

On May 12, 2010, the Company filed a petition with the PUCT which was assigned Docket No. 38253 to refund $10.5 million in fuel cost over-recoveries, including interest, for the period December 2009 through March 2010. On June 14, 2010, the Company and all other parties filed a stipulation that resolved all of the issues in this case. In the stipulation, the Company and the other parties agreed to increase the refund by $0.6 million to remove costs for the purchase of renewable energy credits from the Company's fuel cost, and as a result of that adjustment and the associated recalculation of interest, the total refund was $11.1 million. On June 16, 2010, the Administrative Law Judge assigned to the docket issued an order approving the implementation of interim rates to allow the requested refund to be made in July and August 2010. The PUCT issued a final order on July 15, 2010 approving the stipulation.

On February 18, 2011, the Company filed a petition with the PUCT which was assigned Docket No. 39159 to refund $11.8 million in fuel cost over-recoveries, including interest, for the period October 2010 through December 2010. In its filing, the Company requested the refund be made to customers in the single billing month of April 2011. This case is pending.

Application for Approval to Revise Energy Efficiency Cost Recovery Factor for 2011. On June 1, 2010, the Company filed with the PUCT an application for approval to revise its energy efficiency cost recovery factor ("EECRF"), which was assigned PUCT Docket No. 38226. The Company requested that its revised EECRF become effective beginning with the first billing cycle of its January 2011 billing month. In its application, the Company requested authority to increase its 2011 EECRF to a total of $6.6 million to recover $4.2 million in energy efficiency costs projected to be incurred in 2011, a performance bonus of $0.1 million for the Company's 2009 program performance, and $2.3 million in annual amortization of the energy efficiency costs that were deferred pursuant to the PUCT's final order in Docket No. 35612. A final order approving the Company's application was issued on October 4, 2010.

Application for a Certificate of Convenience and Necessity for Rio Grande Unit 9. On September 30, 2010, the Company filed a petition seeking a Certificate of Convenience and Necessity to construct an 87 MW natural gas-fired combustion turbine unit at the Company's existing Rio Grande Generating Station in the City of Sunland Park in southeast New Mexico. This case was assigned PUCT Docket No. 38717. An intervention deadline of November 15, 2010 was established and the PUCT issued a Preliminary Order in this case on January 26, 2011. The procedural schedule has been suspended while the parties negotiate a settlement.

New Mexico Regulatory Matters

2009 New Mexico Stipulation. On May 29, 2009, the Company filed a general rate case using a test year ended December 31, 2008. The 2009 rate case was docketed as NMPRC Case No. 09-00171-UT. A comprehensive unopposed stipulation (the "2009 New Mexico Stipulation") was reached in this general rate case and filed on October 8, 2009. The 2009 New Mexico Stipulation provided for an increase in New Mexico jurisdictional non-fuel and purchased power base rate revenues of $5.5 million. The 2009 New Mexico Stipulation provided for the revision of depreciation rates for the Palo Verde nuclear generating plant to reflect a 20-year life extension and a revision of depreciation rates for other plant in service. The 2009 New Mexico Stipulation also provided for the continuation of the Company's Fuel and Purchased Power Cost Adjustment Clause ("FPPCAC") without conditions or variance. In addition, it modified the market pricing of capacity and energy provided by Palo Verde Unit 3 using a methodology based upon a previous purchased power contract with Credit Suisse Energy, LLC. On December 10, 2009, the NMPRC issued a final order conditionally approving and clarifying the unopposed stipulation, and the stipulated rates went into effect with January 2010 bills.

Investigation into Recovering County Franchise Fees. On December 10, 2009, the NMPRC issued an order in NMPRC Case No. 09-00421-UT, requiring the Company to show cause why it should collect franchise fees from its customers on behalf of Doña Ana and Otero Counties (the "Counties"). The Company responded to the order on January 5, 2010. On January 26, 2010, the NMPRC issued a final order concluding that the imposition of franchise fees by New Mexico counties is not authorized under New Mexico law and, therefore, the Company may not pass through to its customers some past and all ongoing franchise fees imposed by the Counties. The order concluded that only "home rule" municipalities, who had adopted a charter under the state constitution, could impose franchise fees or taxes, provided the residents so voted.

As a result of its findings, the NMPRC directed the Company to immediately cease passing through to its customers any franchise fees paid by the Company to the Counties. The NMPRC also directed the Company to refund to its customers in the Counties the amount of franchise fees charged to those customers since June 1, 2004, plus interest. The order stated that the Company was required to refund these franchise fees to customers over a three-year period through a credit on customer bills.

The Company filed a Notice of Appeal with the New Mexico Supreme Court on January 27, 2010 (the "Appeal"), seeking to set aside the order on legal and jurisdictional grounds. The Company followed with a motion for Emergency Stay on January 29, 2010, asking the New Mexico Supreme Court to stay the order pending the Appeal. The Company also asked the NMPRC, on February 12, 2010, to delay implementation of its order pending the Appeal. The Counties moved to intervene in the Appeal on February 10, 2010. The Company had placed pending franchise payments to the Counties in separate accounts pending resolution of the proceedings. However, beginning in April 2010 the Company began paying franchise payments to the Counties in accordance with the current franchise agreements. On February 22, 2010, the New Mexico Supreme Court granted the Company's motion for Emergency Stay pending the outcome of the Appeal and granted the Counties' motion to intervene in the Appeal. In February 2010, the New Mexico legislature passed legislation that confirmed the legality of the Company's existing franchise agreements with the Counties. On October 26, 2010, the New Mexico Supreme Court issued its opinion and held that the franchise fee charges fall outside the NMPRC's jurisdiction and vacated and annulled the NMPRC's order.

Investigation into the Service Quality of the Company. On October 22, 2009, NMPRC Staff filed a petition requesting an investigation into the quality of service of the Company's power distribution system in the Santa Teresa Industrial Park, based upon a report prepared for customers in that area by the Los Alamos National Laboratory. On October 27, 2009, the NMPRC decided to initiate an investigation and ordered the Company to respond no later than November 16, 2009. The Company filed an initial response on November 16, 2009 and a supplemental response on January 8, 2010 after obtaining data on which the report was based. The Company responses provided evidence that the reliability and power quality performance for the Company's service territory as a whole and on the Santa Teresa circuits in particular meet all applicable reliability standards and comport with good utility practices. On January 28, 2010, the NMPRC Staff filed a reply stating that it found no factual basis to conclude that the Company had violated NMPRC rules and recommended the NMPRC dismiss this proceeding.

On June 8, 2010, the hearing examiner issued a recommended decision concluding that there is no substantial evidence that would support the allegations in this case regarding the Company's quality of service. The hearing examiner found there is good cause to dismiss the investigation and close the docket without further proceedings. On November 4, 2010, the NMPRC issued a final order approving the recommended decision.

2010 Energy Efficiency Program Approval. On January 19, 2010, the Company filed its Application for Approval of its 2010 Energy Efficiency Programs pursuant to the New Mexico Efficient Use of Energy Act. The filing included changes and additions to the Company's previously approved programs and sought revisions to the associated rate rider through which program costs are recovered. The parties to the proceeding entered into an uncontested stipulation to implement program changes and expansions as well as the rate rider to recover related costs. The NMPRC approved the stipulation in its final order issued August 12, 2010.

2010 Renewable Procurement Plan Pursuant to the Renewable Energy Act. On July 1, 2010, the Company filed its Application for Approval of its 2010 Renewable Procurement Plan, which was assigned NMPRC Case No. 10-00200-UT. The filing included renewable resources intended to meet the Company's Renewable Portfolio Standard ("RPS") requirements in 2011 and future years. The 2010 Renewable Procurement Plan included a number of projects to meet the Company's RPS requirements, including three purchased power agreements for solar energy discussed in "Energy Sources – Purchased Power." In addition, the Company requested a variance from the solar diversity requirements in 2011 to be made up in later years from the new purchased power agreements for solar energy. Hearings were held on October 21, 2010. A final order was issued on December 16, 2010 that approved the Company's 2010 Renewable Procurement plan, including granting the requested variance from the solar diversity requirements in 2011. However, the NMPRC maintained the 2010 rates and contract terms for energy produced by customer-owned renewable distributed generation facilities.

Replacement of Revolving Credit Facility and Guarantee of Debt. On June 22, 2010, the Company received final approval from the NMPRC in Case No. 10-00145-UT to refinance the Company's RCF and issue in a private placement up to $110 million of senior notes by the RGRT, guaranteed by the Company, to finance nuclear fuel. The refinancing of the RCF and the issuance of the senior notes was completed in the third quarter of 2010. See "Energy Sources – Nuclear Fuel – Nuclear Fuel Financing."

Application for Approval to Recover Regulatory Disincentives and Incentives. On August 31, 2010, the Company filed an application for approval of its proposed rate design methodology to recover regulatory disincentives and incentives associated with the Company's energy efficiency and load management programs in New Mexico. A hearing is scheduled for April 25, 2011 and a final order is expected before July 2011.

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, Case No. 07-00443-UT, the NMPRC required each utility to provide information on compensation of executive officers and directors for the period 1977-2006. The Company provided the requested information. No further action was taken by the NMPRC and the case was closed on October 5, 2010.

Application for a Certificate of Convenience and Necessity for Rio Grande Unit 9. On September 30, 2010, the Company filed a petition seeking a Certificate of Convenience and Necessity to construct an 87 MW natural gas-fired combustion turbine unit at the Company's existing Rio Grande Generating Station in the City of Sunland Park in southeast New Mexico. This case was assigned NMPRC Case No. 10-00301-UT. The hearing is scheduled to begin April 13, 2011.

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 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 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, and hearings on the disputed issues were held before an administrative law judge. In the initial decision dated September 6, 2007, the administrative law judge found that the Transmission Agreement allows TEP to transmit power from the LEF 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 exceptions to the initial decision.

On November 13, 2008, the FERC issued an order on the initial decision finding that the transmission rights given to TEP in the Transmission Agreement are firm and are not restricted for transmission of power from Springerville as the receipt point to Greenlee as the delivery point. Therefore, pursuant to the order, TEP can use its transmission rights granted under the Transmission Agreement to transmit power from the LEF to either Springerville or Greenlee so long as it transmits no more than 200 MW over all segments at any one time.

The FERC also ordered that the Company refund to TEP all sums with interest that TEP had paid it for transmission under the applicable transmission service agreements since February 2006 for service relating to the LEF. On December 3, 2008, the Company refunded $9.7 million to TEP. The Company had established a reserve for the rate refund of approximately $7.2 million as of September 30, 2008, resulting in a pre-tax charge to earnings of approximately $2.5 million in 2008. The Company also paid TEP interest on the refunded balance of approximately $0.9 million, which was also charged to earnings in 2008. The Company filed a request for rehearing of the FERC's decision on December 15, 2008, seeking reversal of the order on the merits and a return of any refunds made in the interim, as well as compensation for all service that the Company may provide to TEP from the LEF over the Company's transmission system on a going forward basis. On July 7, 2010, the FERC denied the Company's request for rehearing. On July 23, 2010, the Company filed a petition for review in the United States Court of Appeals for the District of Columbia Circuit and on August 18, 2010, TEP filed a motion to intervene in the proceeding. On January 14, 2011, the Company and TEP filed a joint consent motion, asking the Court to hold the proceedings in abeyance while the parties engaged in settlement discussions. The Court granted the motion on January 19, 2011. If the order is not reversed, or otherwise resolved through settlement, the Company will lose the opportunity to receive compensation from TEP for such transmission service in the future.

In an ancillary proceeding, TEP filed a lawsuit in the United States District Court for the District of Arizona in December 2008, seeking reimbursement for amounts TEP paid a third party transmission provider for purchases of transmission capacity between April 2006 and May 2007, allegedly totaling approximately $1.5 million, plus accrued interest. TEP alleges that the Company was obligated to provide TEP with that transmission capacity without charge under the Transmission Agreement. In September 2009, the Court granted a stay in this suit pending a resolution of the underlying FERC proceeding and any appeal thereof. The Company cannot predict the outcome of this matter.

Replacement of Revolving Credit Facility and Guarantee of Debt. On June 29, 2010, the Company received approval from the FERC in Docket No. ES10-43-000 to refinance the Company's RCF and issue in a private placement up to $110 million of senior notes by the RGRT, guaranteed by the Company, to finance nuclear fuel. The refinancing of the RCF and the issuance of the senior notes was completed in the third quarter of 2010. See "Energy Sources – Nuclear Fuel – Nuclear Fuel Financing."

Department of Energy. The DOE regulates the Company's exports of power to the Comisión Federal de Electricidad 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 ("NRC"). 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. See "Facilities – Palo Verde Station" for discussion regarding application to extend the Palo Verde licenses for 20 years.

Sales for Resale

The Company provides firm capacity and associated energy to the RGEC pursuant to an ongoing contract which requires a two-year notice to terminate. The Company also provides network integrated transmission service to RGEC pursuant to the Company's Open Access Transmission Tariff ("OATT"). The contract includes a formula-based rate that is updated annually to recover non-fuel generation costs and a fuel adjustment clause designed to recover all eligible fuel and purchased power costs allocable to RGEC.

C. Regulatory Assets and Liabilities

The Company's operations are regulated by the PUCT, the NMPRC and the FERC. Regulatory assets represent probable future recovery of previously incurred costs, which will be collected from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are to be credited to customers through the ratemaking process. Regulatory assets and liabilities reflected in the Company's consolidated balance sheets are presented below (in thousands):

	Amortization Period Ends	December 31, 2010	December 31, 2009
Regulatory assets			
Regulatory tax assets (a)	(b)	$ 37,230	$ 29,927
Loss on reacquired debt (h)	May 2030	20,897	5,374
Final coal reclamation (a)	July 2016	10,282	9,381
Nuclear fuel postload daily financing charge	(d)	2,007	1,586
Unrecovered issuance costs due to reissuance of PCBs	April 2040	599	619
Texas energy efficiency	(d)	5,460	4,017
Texas 2009 rate case costs (c)	June 2012	3,298	1,473
Texas military base discount and recovery factor	(e)	761	0
New Mexico 2009 rate case procurement plan costs (c)	December 2011	232	464
New Mexico procurement plan costs	(f)	122	112
New Mexico 2009 rate case renewable energy credits (c)	December 2011	1,139	3,123
New Mexico renewable energy credits	(f)	930	292
New Mexico 2006 rate case costs (c)	June 2010	0	95
New Mexico 2009 rate case costs (c)	December 2012	506	814
New Mexico Palo Verde deferred depreciation	(b)	4,773	2,789
New Mexico energy efficiency	(d)	321	642
Total regulatory assets		$ 88,557	$ 60,708
Regulatory liabilities			
Regulatory tax liabilities (a)	(b)	$ 9,326	$ 8,858
Accumulated deferred investment tax credit (g)	(b)	5,163	5,269
Total regulatory liabilities		$ 14,489	$ 14,127

(a) No specific return on investment is required since related assets and liabilities, including accumulated deferred income taxes and reclamation liability, offset.
(b) The amortization period for this asset is based upon the life of the associated assets.
(c) This item is included in rate base which earns a return on investment.
(d) This asset is recovered through an annual recovery factor.
(e) This item represents the net asset related to the military discount which is recovered from non-military customers through a recovery factor.
(f) Amortization period is anticipated to be established in next general rate case.
(g) This item is excluded from rate base.
(h) This item is recovered as a component of the weighted cost of debt.

D. 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, 2010 (in thousands):

	Gross Plant	Accumulated Depreciation	Net Plant
Nuclear production	$ 772,710	$ (225,461)	$ 547,249
Steam and other	376,653	(203,093)	173,560
Total production	1,149,363	(428,554)	720,809
Transmission	375,164	(232,470)	142,694
Distribution	810,667	(290,688)	519,979
General	127,618	(70,846)	56,772
Intangible	60,050	(24,940)	35,110
Total	$ 2,522,862	$ (1,047,498)	$ 1,475,364

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 $6.3 million, $4.5 million and $4.1 million for 2010, 2009 and 2008, respectively. The table below presents the estimated amortization expense for intangible plant for the next five years (in thousands):

2011	$ 6,185
2012	5,765
2013	4,765
2014	3,796
2015	3,143

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, 2010 and 2009 is as follows (in thousands):

	December 31, 2010		December 31, 2009	
	Palo Verde	Other	Palo Verde	Other
Electric plant in service	$ 772,710	$ 209,427	$ 729,174	$ 204,390
Accumulated depreciation	(225,461)	(159,679)	(207,460)	(156,250)
Construction work in progress	48,703	1,940	57,201	5,290
Total	$ 595,952	$ 51,688	$ 578,915	$ 53,430

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"). Arizona Public Service ("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.

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 enables the Company to record a current deduction for federal income tax purposes for most of the amounts funded. At December 31, 2010, the Company's decommissioning trust fund had a balance of $153.9 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. On March 26, 2008, the Palo Verde Participants approved the 2007 Palo Verde decommissioning study (the "2007 Study"). The 2007 Study estimated that the Company must fund approximately $324.4 million (stated in 2007 dollars) to cover its share of decommissioning costs which was a reduction in decommissioning costs from the 2004 Palo Verde decommissioning study and will result in lower asset retirement obligations and lower expenses in the future. Although the 2007 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 commissioned in 2010 ("2010 Study"). The final application of the 2010 Study is pending the NRC's decision to approve the application to extend the Palo Verde licenses for 20 years as discussed above. 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 on-site facilities until accepted by the DOE for permanent disposal. The 2007 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 current 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. In November 1997, the United States Court of Appeals for the District of Columbia Circuit issued a decision preventing the DOE from excusing its own delay but refused to order the DOE to begin accepting spent nuclear fuel. The Company cannot predict when spent fuel shipments to the DOE 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. APS pursued a damages claim for costs incurred through December 2006 in a trial that began on January 28, 2009. On June 18, 2010, the court awarded APS and the other Palo Verde Participants approximately $30 million. In October 2010, the Company received $4.8 million, representing its share of the award. The majority of the award was refunded to customers through the applicable fuel adjustment clauses. APS is continuing to pursue settlement of damage claims for costs incurred after 2006.

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. The construction and opening of low-level radioactive waste disposal sites have been delayed due to extensive public hearings, disputes over environmental issues and review of technical issues related to the proposed sites. The opposition, delays, uncertainty and costs that have been experienced 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.

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 $12.6 billion. This potential liability is covered by primary liability insurance provided by commercial insurance carriers in the amount of $375 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 $117.5 million, subject to an annual limit of $17.5 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 $55.7 million, with an annual payment limitation of approximately $8.3 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 $8.95 million for the current policy period.

E. Accounting for Asset Retirement Obligations

The Company complies with FASB guidance for asset retirement obligations ("ARO"). This guidance 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 also complies with FASB guidance for conditional asset retirements which primarily affects 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. The Company's AROs 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. The Company records the increase in the ARO due to the passage of time as an operating expense (accretion expense). 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.

The ARO liability for Palo Verde is based upon the estimated cost of decommissioning the plant from the 2007 Palo Verde decommissioning study. See Note D. 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. The Company assumed an escalation rate of 3.6%. Since the 2007 Palo Verde decommissioning cost estimate is less than the original estimate in 2007 dollars, the Company used the credit-risk adjusted discount rate of 9.5% used in the original calculation of the ARO liability. 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. Because the DOE is obligated to assume 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, 2010 is $153.9 million.

FASB guidance 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 2007 study reflected a downward revision in the estimated cash flows for decommissioning costs from the 2004 study, the Company recorded an $8.6 million reduction to its ARO asset and liability in the first quarter of 2008. Accretion and depreciation expense related to the ARO decreased approximately $1.3 million annually as a result of this adjustment.

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

	2010	2009	2008
ARO liability at beginning of year	$ 85,358	$ 78,037	$ 79,709
Liabilities incurred	0	0	0
Liabilities settled	(85)	0	0
Revisions to estimate	(377)	0	(8,559)
Accretion expense	8,015	7,321	6,887
ARO liability at end of year	$ 92,911	$ 85,358	$ 78,037

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.

F. 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 Plan

On May 2, 2007, the Company's shareholders approved a stock-based long-term incentive plan (the "2007 LTIP") and authorized the issuance of up to one million shares of common stock for the benefit of directors and employees. Under the 2007 LTIP, 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. 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 the 2007 LTIP. As discussed in Note A, the Company accounts for its stock-based long-term incentive plan under FASB guidance for stock-based compensation.

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 2010:

	Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value (In thousands)
Options outstanding at December 31, 2009	197,988	$ 13.51		
Options exercised	96,742	14.25		
Options outstanding at December 31, 2010	101,246	12.82	1.96	$ 1,490
Exercisable at December 31, 2010	101,246	12.82	1.96	1,490

The Company received approximately $1.4 million in cash for the 96,742 stock options exercised in 2010. During 2010, the Company realized $0.3 million in current tax benefits from the exercise of stock options. The intrinsic value of stock options exercised in 2010, 2009 and 2008 was $1.3 million, $1.5 million and $1.0 million, respectively. No options were forfeited, vested or expired during 2010 and 2009. The fair value at grant date of options vested during 2008 was $0.1 million.

All stock options outstanding have vested. No compensation cost was recognized in 2008, 2009, and 2010 for stock options and there is no unrecognized compensation expense related to stock options.

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 the unvested restricted stock at the date of grant is amortized to expense over the restriction period net of anticipated forfeitures.

Approximately $1.6 million, $1.5 million and $1.4 million was charged to expense related to restricted stock awards in 2010, 2009 and 2008, respectively. The deferred tax benefit related to these expenses was $0.6 million, $0.6 million, and $0.5 million for 2010, 2009 and 2008, respectively. Current tax expense of $0.2 million, $0.2 million, and $0.1 million was recognized by the Company in 2010, 2009 and 2008 from the issuance of restricted stock, respectively. 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 2010, 2009 and 2008 was $1.7 million, $1.3 million and $1.6 million, respectively. The fair value at grant date for restricted stock vested in 2010, 2009 and 2008 was $1.3 million, $1.7 million and $1.8 million, respectively. The outstanding restricted stock has remaining $1.2 million of unrecognized compensation expense at December 31, 2010 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 143,371 outstanding restricted shares at December 31, 2010 was $3.9 million.

The following table summarizes the unvested restricted stock transactions for 2010:

	Total Shares	Weighted Average Grant Date Fair Value
Restricted shares outstanding at December 31, 2009	147,427	$ 15.74
Restricted stock awards	112,891	20.03
Lapsed restrictions and vesting	(78,954)	16.02
Forfeitures	(37,993)	18.20
Restricted shares outstanding at December 31, 2010	143,371	18.30

The weighted average fair values per share at grant date for restricted stock awarded during 2010, 2009 and 2008 were $20.03, $14.59 and $20.05, 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 share awards. Performance shares vesting on January 1, 2010 met the 30% payout level and 9,525 shares were issued with a total cost of $0.7 million which had been expensed ratably between 2007 and 2009. The requisite service period for these shares ended December 31, 2009, and the shares had an aggregate intrinsic value of $0.2 million. Performance shares vesting on January 1, 2011 met the 112.5% payout level and 34,820 shares were issued with a total cost of $0.6 million which had been expensed ratably between 2008 and 2010. The requisite service period for these shares ended December 31, 2010, and the shares had an aggregate intrinsic value of $1.0 million. In 2011, 2012 and 2013, subject to meeting certain performance criteria, additional performance shares could be awarded. In accordance with FASB guidance related to stock-based compensation, the Company recognizes the related compensation expense by ratably amortizing the grant date fair value of awards over the requisite service period and the compensation expense is only adjusted for forfeitures. The actual number of shares issued can range from zero to 403,500 shares.

The fair 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 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, 2009	192,100	$ 14.58
Performance share awards	96,900	19.82
Performance shares vested	(9,525)	20.86
Performance shares lapsed	(22,225)	20.86
Performance shares forfeited	(24,550)	12.91
Performance shares outstanding at December 31, 2010	232,700	16.08

The outstanding performance awards have remaining $1.5 million of unrecognized expense at December 31, 2010 that is expected to be recognized over the weighted average remaining contractual term of the awards of approximately one year. The aggregate intrinsic value of the 232,700 outstanding awards (based on 100% performance level) at December 31, 2010 was $6.4 million. The weighted average per share grant date fair value per share of performance shares awarded during the years 2010, 2009 and 2008 was $19.82, $12.00, and $17.14, respectively. The fair value of performance shares which vested in 2010 and 2008 was $0.2 million and $0.8 million, respectively, with an intrinsic value of $0.2 million and $0.9 million, respectively.

The Company recorded compensation expense related to performance shares of $1.0 million, $0.7 million and $0.8 million in 2010, 2009 and 2008, respectively. The compensation expense for 2010, 2009 and 2008 included cumulative adjustments for forfeiture of performance share awards by certain executives. Deferred tax expense related to compensation expense in 2010, 2009 and 2008 was $0.3 million.

Common Stock Repurchase Program

Since the inception of the stock repurchase program in 1999, the Company has repurchased a total of approximately 22.6 million shares of its common stock at an aggregate cost of $337.1 million, including commissions. On February 19, 2010, the Board of Directors authorized an additional repurchase of up to 2 million shares of the Company's outstanding common stock. During 2010, 1,524,711 shares were repurchased in the open market at an aggregate cost of $33.7 million, including commissions. As of December 31, 2010, 676,271 shares remain authorized for repurchase under its authorized program. The Company may in the future make purchases of its common stock pursuant to its authorized program 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.

Basic and Diluted Earnings Per Share

Effective January 1, 2009, the Company adopted FASB guidance which requires a public entity to include share-based compensation awards that qualify as participating securities in both basic and diluted earnings per share to the extent they are dilutive. A share-based compensation award is considered a participating security if it receives non-forfeitable dividends or may participate in undistributed earnings with common stock. The Company awards unvested restricted stock which qualifies as a participating security. The basic and diluted earnings per share are presented below:

	Year Ended December 31,		
	2010	2009	2008
Weighted average number of common shares outstanding:			
Basic number of common shares outstanding	43,129,735	44,524,146	44,777,765
Dilutive effect of unvested performance awards	101,780	27,876	15,820
Dilutive effect of stock options	62,904	43,045	136,524
Diluted number of common shares outstanding	43,294,419	44,595,067	44,930,109
Basic net income per common share:			
Net income	$ 100,603	$ 66,933	$ 77,621
Income allocated to participating restricted stock	(403)	(240)	(189)
Net income available to common shareholders	$ 100,200	$ 66,693	$ 77,432
Diluted net income per common share:			
Net income	$ 100,603	$ 66,933	$ 77,621
Income reallocated to participating restricted stock	(401)	(240)	(188)
Net income available to common shareholders	$ 100,202	$ 66,693	$ 77,433
Basic net income per common share	$ 2.32	$ 1.50	$ 1.73
Diluted net income per common share	$ 2.31	$ 1.50	$ 1.72

The calculation of the weighted average number of common shares and dilutive potential shares outstanding for the year ended December 31, 2010, 2009 and 2008 excludes 75,270, 66,628 and 50,748 shares, respectively, of restricted stock awards because their effect was antidilutive.

Performance shares of 24,225, 161,842 and 122,479 were excluded from the computation of diluted earnings per share for the year ended December 31, 2010, 2009 and 2008, respectively, as no payments would be required based upon current performance. These amounts assume a 100% performance level payout.

No stock options were excluded from the computation of diluted earnings per share for the year ended December 31, 2010 and 2008. Stock options of 53,610 were excluded from the computation of diluted earnings per share for the year ended December 31, 2009 as the exercise price was greater than the average stock price for the period.

G. 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, 2007	$ 15,363	$ 11,737	$ (13,560)	$ 13,540
Other comprehensive income (loss)	(26,903)	(33,493)	297	(60,099)
Income tax benefit (expense)	5,381	11,922	(108)	17,195
Balance at December 31, 2008	(6,159)	(9,834)	(13,371)	(29,364)
Other comprehensive income (loss)	15,034	(49,709)	317	(34,358)
Income tax benefit (expense)	(3,007)	16,957	(115)	13,835
Balance at December 31, 2009	5,868	(42,586)	(13,169)	(49,887)
Other comprehensive income	6,787	17,351	338	24,476
Income tax expense	(1,357)	(6,287)	(122)	(7,766)
Balance at December 31, 2010	$ 11,298	$ (31,522)	$ (12,953)	$ (33,177)

H. Long-Term Debt and Financing Obligations

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

	December 31,	
	2010	2009
	(In thousands)	
Long-Term Debt:		
Pollution Control Bonds (1):		
7.25% 2009 Series A refunding bonds, due 2040	$ 63,500	$ 63,500
4.80% 2005 Series A refunding bonds, due 2040	59,235	59,235
7.25% 2009 Series B refunding bonds, due 2040	37,100	37,100
4.00% 2002 Series A refunding bonds, due 2032	33,300	33,300
Senior Notes (2):		
6.00% Senior Notes, net of discount, due 2035	397,856	397,822
7.50% Senior Notes, net of discount, due 2038	148,754	148,740
RGRT Senior Notes (3):		
3.67% Senior Notes, Series A, due 2015	15,000	0
4.47% Senior Notes, Series B, due 2017	50,000	0
5.04% Senior Notes, Series C, due 2020	45,000	0
Total long-term debt	849,745	739,697
Financing Obligations:		
Revolving Credit Facility ($4,704 due in 2011) (4)	4,704	106,998
Total long-term debt and financing obligations	854,449	846,695
Current Portion (amount due within one year)	(4,704)	(41,720)
	$ 849,745	$ 804,975

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(1) Pollution Control Bonds ("PCBs")

The Company has four series of tax exempt PCBs in an aggregate principal amount of approximately $193.1 million. The 2005 Series A $59.2 million bonds which mature in 2040, have a fixed interest rate of 4.80% and an effective interest rate of 5.27% after considering related insurance and issuance costs. The 2002 Series A $33.3 million pollution control bonds bear a fixed interest rate of 4.00% until August 1, 2012 when 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.

On March 26, 2009, the Company completed a refunding transaction whereby the 2005 Series B $63.5 million bonds and the 2005 Series C $37.1 million bonds were refunded and replaced by 2009 Series A bonds in the aggregate principal amount of $63.5 million (the "2009 Series A Bonds") and 2009 Series B bonds in the aggregate principal amount of $37.1 million (the "2009 Series B Bonds"). The 2009 Series A Bonds and the 2009 Series B Bonds were issued as unsecured obligations and both have a fixed interest rate of 7.25%. The 2009 Series A Bonds will mature on February 1, 2040 and have an effective interest rate of 7.42% after considering related issuance costs. The 2009 Series B Bonds will mature on April 1, 2040 and have an effective interest rate of 7.42% after considering related issuance costs.

(2) Senior Notes

In May 2005, the Company issued $400.0 million aggregate principal amount of its 6% Senior Notes due May 15, 2035. The proceeds from the issuance of the 6% Senior 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.

In June 2008, the Company issued $150.0 million aggregate principal amount of its 7.5% Senior Notes due March 15, 2038. Proceeds from the issuance of the 7.5% Senior Notes of $148.7 million ($150 million principal amount net of a $1.3 million discount) were used to repay short-term borrowings of $44.0 million. The remaining proceeds were used to fund capital expenditures and for other general corporate purposes. The Senior Notes are unsecured obligations of the Company. They were issued pursuant to bond covenants that provide limitations on the Company's ability to enter into certain transactions.

(3) RGRT Senior Notes

On August 17, 2010, the Company and RGRT, a Texas grantor trust through which the Company finances its portion of fuel for the Palo Verde entered into a Note Purchase Agreement (the "Agreement") with various institutional purchasers. Under the terms of the Agreement, RGRT sold to the purchasers $110 million aggregate principal amount of senior notes consisting of (a) $15 million aggregate principal amount of 3.67% RGRT Senior Notes, Series A, due August 15, 2015, with an effective interest rate of 3.87%, (b) $50 million aggregate principal amount of 4.47% RGRT Senior Notes, Series B, due August 15, 2017, with an effective interest rate of 4.62% and (c) $45 million aggregate principal amount of 5.04% RGRT Senior Notes, Series C, due August 15, 2020, with an effective interest rate of 5.16% (collectively, the "Notes"). The Company guarantees the payment of principal and interest on the Notes. In the Company's financial statements, the assets and liabilities of the RGRT are reported as assets and liabilities of the Company.

RGRT will pay interest on the Notes on February 15 and August 15 of each year until maturity, beginning on February 15, 2011. RGRT may redeem the Notes, in whole or in part, at any time at a redemption price equal to 100% of the principal amount to be redeemed together with the interest on such principal amount accrued to the date of redemption, plus a make-whole amount based on the prevailing market interest rates. The Agreement requires compliance with certain covenants, including a total debt to capitalization ratio. The Company was in compliance with these requirements throughout 2010.

The sale of the Notes was made by RGRT in reliance on a private placement exemption from registration under the Securities Act of 1933, as amended.

The proceeds of $109.4 million, net of issuance costs, from the sale of the Notes was used by RGRT to repay amounts borrowed under the revolving credit facility and will enable future nuclear fuel financing requirements of RGRT to be met with a combination of the Notes and amounts borrowed from the revolving credit facility.

(4) Revolving Credit Facility

Prior to September 23, 2010, the Company had available a $200 million credit facility with a five-year term ending April 2011. The credit facility provided for up to $120 million for the financing of nuclear fuel, which was accomplished through the RGRT that borrowed under the facility to acquire and process the nuclear fuel. The Company was obligated to repay the RGRT's borrowings with interest. Any amounts not borrowed by the RGRT could have been borrowed by the Company for working capital needs.

On September 23, 2010, the Company and RGRT entered into a new revolving credit agreement (the "RCF") with JP Morgan Chase Bank, N.A., as administrative agent and issuing bank, and Union Bank, N.A., as syndication agent, and various lending banks party thereto. Under the terms of the RCF, the Company and RGRT have available $200 million of credit for a term of four years. The Company may request that the RCF be increased up to a total of $300 million during the term of the RCF, subject to lender approval.

The RCF provides that amounts borrowed by the Company may be used for, among other things, working capital and general corporate purposes. Any amounts borrowed by RGRT may be used, among other things, to finance the acquisition and processing of nuclear fuel. Amounts borrowed by RGRT are guaranteed by the Company and the balance borrowed under the RCF is recorded as a financing obligation on the consolidated balance sheet. The RCF is unsecured. The RCF requires compliance with certain covenants, including a total debt to capitalization ratio. The Company was in compliance with these requirements throughout 2010. At December 31, 2010, RGRT had $4.7 million outstanding for nuclear fuel under the RCF. No amounts were outstanding under this facility for working capital needs as of December 31, 2010. The weighted average interest rate on the RCF was 2.6% as of December 31, 2010.

As of December 31, 2010, the scheduled maturities for the next five years of long-term debt are as follows (in thousands):

2011	$ 0
2012	33,300
2013	0
2014	0
2015	15,000

Future obligations and maturities related to nuclear fuel financing obligations estimated to be paid in 2011 are $4.7 million. Specific maturity dates are not known, as maturities occur as fuel is burned.

I. Income Taxes

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and liabilities at December 31, 2010 and 2009 are presented below (in thousands):

	December 31,	
	2010	2009
Deferred tax assets:		
Alternative minimum tax credit carryforward	$ 18,370	$ 28,267
Pensions and benefits	58,978	68,037
Asset retirement obligation	32,519	29,875
Deferred fuel	6,727	6,306
Other	4,054	10,501
Total gross deferred tax assets	120,648	142,986
Deferred tax liabilities:		
Plant, principally due to depreciation and basis differences	(328,310)	(306,325)
Decommissioning	(36,709)	(33,621)
Other	(16,541)	(16,019)
Total gross deferred tax liabilities	(381,560)	(355,965)
Net accumulated deferred income taxes	$ (260,912)	$ (212,979)

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 deferred tax assets will be fully realized at current levels of book and taxable income.

The Company recognized income tax expense for 2010, 2009, and 2008 as follows (in thousands):

	Years Ended December 31,		
	2010	2009	2008
Income tax expense:			
Federal:			
Current	$ 19,251	$ (10,123)	$ 18,324
Deferred	31,279	39,537	15,525
Total federal income tax	50,530	29,414	33,849
State:			
Current	4,308	2,321	3,242
Deferred	1,947	1,309	739
Total state income tax	6,255	3,630	3,981
Total income tax expense	56,785	33,044	37,830
Tax expense classified as extraordinary gain	(5,769)	0	0
Total income tax expense before extraordinary item	$ 51,016	$ 33,044	$ 37,830

Current federal income tax expense for 2010 and 2008 reflects taxes accrued under the alternative minimum tax ("AMT"). Deferred federal income tax for 2010 and 2008 includes an offsetting AMT benefit of $10.2 million and $8.1 million respectively. There was no offsetting AMT benefit for 2009. As of December 31, 2010, the Company had $18.4 million of AMT credit carryforwards that have an unlimited life.

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,		
	2010	2009	2008
Federal income tax expense computed on income at statutory rate	$ 55,086	$ 34,992	$ 40,408
Difference due to:			
State taxes, net of federal benefit	4,066	2,360	2,588
AEFUDC	(3,578)	(3,051)	(2,690)
Permanent tax differences	(3,103)	(618)	(1,935)
Patient Protection and Affordable Care Act	4,787	0	0
Other	(473)	(639)	(541)
Total income tax expense	56,785	33,044	37,830
Tax expense classified as extraordinary gain	(5,769)	0	0
Total income tax expense before extraordinary item	$ 51,016	$ 33,044	$ 37,830
Effective income tax rate	36.1%	33.1%	32.8%

On March 23, 2010, the Patient Protection and Affordable Care Act ("PPACA") was signed into law. A major provision of the law is that, beginning in 2013, the income tax deductions for the cost of providing certain prescription drug coverage will be reduced by the amount of the Medicare Part D subsidies received. The Company was required to recognize the impacts of the tax law change at the time of enactment and recorded a one-time non-cash charge to income tax expense of approximately $4.8 million in the first quarter of 2010. The Company's effective tax rate without the effects of the enactment of the PPACA for the year ended December 31, 2010 would have been 33.0%.

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 jurisdiction for years prior to 2007 and in the state jurisdictions for years prior to 1998. On January 6, 2010, the Company reached a settlement with the IRS for the years 2005 and 2006. In the settlement of the tax years 2005 and 2006, the Company agreed with the IRS to the tax treatment for the steam generators in the same manner as settled in the 1999 through 2004 audit which is the deduction in the year incurred of 40% of payments related to the repair of the Palo Verde steam generators and the capitalization and depreciation of the remaining 60% of those payments. The IRS settlement affected the timing of these deductions but not their ultimate deductibility for federal tax purposes. A deficiency notice relating to the Company's 1998 through 2003 income tax returns in Arizona contests a pollution control credit, a research and development credit and the sales and property apportionment factors. The Company is contesting these adjustments.

FASB guidance 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. In January 2010, the Company filed for a change of accounting method with the IRS related to the way in which units of property are determined for purposes of determining capitalized tax assets. The change was included in the 2009 federal income tax return. The Company recorded an additional unrecognized tax position of $6.3 million related to the change in accounting method in the third quarter of 2010. An additional unrecognized tax position may be recognized after the IRS audits the 2009 tax return. A reconciliation of the December 31, 2010, 2009 and 2008 amount of unrecognized tax benefits is as follows (in millions):

	2010	2009	2008
Balance at January 1	$ 0.6	$ 0.5	$ 8.5
Additions/(reductions) based on tax positions related to the current year	6.3	0.0	(0.7)
Additions for tax positions of prior years	0.4	0.4	2.6
Reductions for tax positions of prior years	0.0	(0.3)	(0.3)
Reductions for IRS settlement	0.0	0.0	(9.6)
Balance at December 31	$ 7.3	$ 0.6	$ 0.5

If recognized, $1.0 million of the unrecognized tax position at December 31, 2010, would affect the effective tax rate. The Company recognized income tax expense for an unrecognized tax position of $0.1 million for the year ended December 31, 2009.

The Company recognizes in tax expense interest and penalties related to tax benefits that have not been recognized. During the years ended December 31, 2010, 2009 and 2008, the Company recognized benefits of approximately $0.1 million, $0.2 million and $0.9 million, respectively, in interest. The Company had approximately $0.2 million and $0.2 million for the payment of interest and penalties accrued at December 31, 2010 and December 31, 2009, respectively.

J. Commitments, Contingencies and Uncertainties

Federal Regulatory Matters

See Note B – Federal Regulatory Matters – *Transmission Dispute with Tucson Electric Power Company,* for discussion of the Company's transmission dispute with TEP.

Power Purchase and Sale 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 (1)	2006 through 2021
Power Purchase Agreement	Up to 40 MW	2011 through September 2014
Power Purchase Agreement	20 MW	20 years after operational start date (2)
Power Purchase Agreement	24 MW	25 years after operational start date (3)
Power Purchase Agreement	5 MW	25 years after operational start date (4)

(1) In accordance with the purchase agreement, the allowed purchase quantity was increased to 125 MW from December 2008 through December 2011.

(2) This contact is a power purchase agreement for the full capacity of a 20 MW solar photovoltaic plant to be built in southern New Mexico. The plant is scheduled to begin commercial operation by December 31, 2011.

(3) This contract is a purchase power agreement for the full capacity of two 12 MW solar photovoltaic plants to be built in southern New Mexico. One of these plants is scheduled for commercial operation by December 31, 2011. The second plant is scheduled to begin commercial operation by June 30, 2012.

(4) This contract is a power purchase agreement for the full capacity of a 5 MW solar photovoltaic plant to be built in southern New Mexico. The plant is scheduled to begin commercial operation by June 30, 2011.

To supplement its own generation and operating reserves, the Company engages in 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.

The Company initiated a Power Purchase and Sale Agreement with Freeport-McMoran Copper and Gold Energy Services LLC ("Freeport") formerly known as Phelps Dodge Energy Services LLC in June 2006. The contract provides for Freeport to deliver energy to the Company from its ownership interest in the Luna Energy Facility (a 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 Greenlee, Arizona. The Company may purchase up to 100 MW at a specified price at times when energy is not exchanged under the Power Purchase and Sale Agreement. Upon mutual agreement, the contract allows the parties to increase the amount of energy that is purchased and sold under the Power Purchase and Sale Agreement. The parties agreed to increase the amount to 125 MW from December 2008 through December 2011. The contract was approved by the FERC and continues through December 31, 2021.

The Company entered into a contract on April 18, 2007 (as amended on August 29, 2008, March 31, 2009 and May 8, 2009) 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 continued through October 31, 2009. The contract provided for 100 MW firm energy and 40 MW of contingent energy to continue through April 30, 2010, when the contract terminated. To ensure that power was available to meet the IID contract demand, the Company entered into a contract effective May 1, 2007 (as amended and restated on September 3, 2008 and March 30, 2009) to purchase up to 100 MW of firm energy 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 2009.

The Company entered into an agreement in 2009 to purchase capacity of up to 40 MW and unit contingent energy during 2010 from Shell Energy North America ("Shell"). Under the agreement, the Company provides natural gas to Pyramid Unit No. 4 where Shell has the right to convert natural gas to electric energy. The Company entered into a contract with Shell on May 17, 2010 to extend the term of the capacity and unit contingency energy purchase from January 1, 2011 through September 30, 2014.

The Company entered into a 20-year contract with New Mexico SunTower, LLC ("NM SunTower") in 2008 for the purchase of the output of a 92-MW concentrated solar plant which was expected to begin commercial operation in 2011. NM SunTower is an affiliate of NRG Energy, Inc. NM SunTower failed to meet its financial commitment milestone, and, on May 3, 2010, the Company delivered to NM SunTower a notice of default as provided under the terms of the contract. The Company presented testimony to the NMPRC at a hearing June 8, 2010, seeking approval for NM SunTower's request to revise the contract to (i) change the technology from concentrated solar to photovoltaic, (ii) downsize the solar project from 92 MW to 20 MW, and (iii) delay the date for commercial operation to December 31, 2011, at the earliest. The Company also requested deferral of its 2011 solar diversity requirements to the 2012-2015 period and approval to meet its 2011 renewable portfolio standard ("RPS") with purchases of renewable energy credits ("RECs") from a third party. On June 24, 2010, the NMPRC approved changes to the contract with NM SunTower.

On July 1, 2010, the Company made its annual Plan filing requesting approval for 25-year purchase power agreements for two additional solar photovoltaic projects totaling 24 MW, consisting of two 12 MW projects located in southern New Mexico with the first expected to be operational by December 31, 2011. The second 12 MW project is expected to be operational by June 30, 2012. The Company also requested approval for a 25-year purchase power agreement for a 5 MW photovoltaic project also located in southern New Mexico expected to be operational by June 30, 2011. In addition, approval for the purchase of RECs to meet the Company's RPS requirements for the 2011 to 2015 period was requested. The NMPRC approved the contracts and the Company's request to purchase RECs to meet RPS requirements in its final order issued December 16, 2010.

The Company provides firm capacity and associated energy to the RGEC pursuant to an ongoing contract which requires a two-year notice to terminate. The Company also provides network integrated transmission service to RGEC pursuant to the Company's Open Access Transmission Tariff ("OATT"). The contract includes a formula-based rate that is updated annually to recover non-fuel generation costs and a fuel adjustment clause designed to recover all eligible fuel and purchased power costs allocable to RGEC.

Environmental Matters

General. The Company is subject to laws and regulations with respect to air, soil and water quality, waste disposal and other environmental matters by federal, state, regional, tribal and local authorities. Those authorities govern 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 or other sanctions. In addition, releases of pollutants or contaminants into the environment can result in costly cleanup obligations. 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. Certain key environmental issues, laws and regulations facing the Company are described further below.

Air Emissions. The U.S. Clean Air Act ("CAA") and comparable state laws and regulations relating to air emissions impose, among other obligations, limitations on pollutants generated during the Company's operations, including sulfur dioxide ("SO2"), particulate matter, nitrogen oxides ("NOx") and mercury.

Clean Air Interstate Rule. The U.S. Environmental Protection Agency's ("EPA") Clean Air Interstate Rule ("CAIR") as applied to the Company, involves requirements to limit emissions of NOx from the Company's power plants in Texas and/or purchase allowances representing other parties' emissions reductions starting in 2009. Although the U.S. Court of Appeals for the District of Columbia voided CAIR in 2008, the Company must comply with CAIR until the EPA rewrites the rule as required by the Court's final opinion. The 2010 reconciliation to comply with CAIR is due March 2011 and the Company purchased and expensed $0.3 million of allowances during 2010 to meet its estimated requirement.

Clean Air Transport Rule. In July 2010, the EPA proposed as a replacement to CAIR, the Clean Air Transport Rule ("CATR"). CATR would require 31 states, including Texas, and the District of Columbia to issue regulations and develop a scheme by which power plants in their respective jurisdictions will further reduce emissions of SO2 and NOx. Reductions would be required beginning in 2012, with further reductions likely to be required in 2014. The EPA expects CATR to be finalized in July 2011, but it is unclear when the states would issue implementing regulations. There are a number of other uncertainties relating to this proposed rule, including whether it will be ultimately finalized and how the states will implement the requirements. As a result, the ultimate impact of this rule on the Company's operations cannot currently be determined, but it could be material.

Ozone. NOx emissions can lead to the formation of ozone. Ozone levels are limited by the National Ambient Air Quality Standards established by the EPA. The EPA is in the process of revising these standards. If these revisions result in more stringent standards, the Company could be required to place additional NOx pollution control measures on certain of its generating facilities. Without knowing the new ozone standards, the ultimate impact on the Company's facilities cannot be determined. However the impact of these regulations and associated costs could be material.

Climate Change. A significant portion of the Company's generation assets are nuclear or gas-fired, and as a result, the Company believes that its greenhouse gas ("GHG") emissions are low relative to electric power companies who rely on more coal-fired generation. However, regulations governing the emission of GHGs, such as carbon dioxide, could impose significant costs or limitations on the Company. In recent years, the U.S. Congress has considered new legislation to restrict or regulate GHG emissions, although federal efforts directed at enacting comprehensive climate change legislation stalled in 2010 and appear highly unlikely to recommence in 2011. Nonetheless, it is possible that federal legislation related to GHG emissions will be considered in Congress in the future. The EPA has also proposed using the CAA to limit carbon dioxide and other GHG emissions, and GHG emissions regulations have been adopted by EPA in recent years, with additional regulations proposed or in development.

Significant GHG emissions regulations have been adopted by EPA in recent years with additional regulations proposed or in development. In September 2009, the EPA adopted a rule requiring approximately 10,000 facilities comprising a substantial percentage of annual U.S. GHG emissions to inventory their emissions starting in 2010 and to report those emissions to the EPA beginning in 2011. The Company's fossil fuel-fired power generating assets are subject to this rule. The Company also has inventoried and implemented procedures for electrical equipment containing sodium hexafluoride (SF6), another GHG. The Company is tracking these GHG emissions pursuant to EPA's new SF6 reporting rule that was finalized in late 2010 and became effective January 1, 2011. The first report to EPA under this rule is due March 31, 2012.

EPA has also proposed and finalized other rulemakings on GHG emissions that affect electric utilities. Under EPA regulations finalized in May 2010 (referred to as the "Tailoring Rule"), the EPA began regulating GHG emissions from certain stationary sources in January 2011. The regulations are being implemented pursuant to two CAA programs: the Title V Operating Permit program and the program requiring a permit if undergoing construction or major modifications (referred to as the "PSD" program). Obligations relating to Title V permits will include recordkeeping and monitoring requirements. With respect to PSD permits, projects that cause a significant increase in GHG emissions (currently defined to be more than 75,000 tons or more per year or 100,000 tons or more per year, depending on various factors), will be required to implement "best available control technology", or "BACT". The EPA has issued guidance on what BACT entails for the control of GHGs and individual states are now required to determine what controls are required for facilities within their jurisdiction on a case-by-case basis. The ultimate impact of these new regulations on the Company's operations cannot be determined at this time, but the cost of compliance with new regulations could be material. Also, on December 23, 2010, EPA announced a settlement agreement with states and environmental groups regarding setting new source performance standards for GHG emissions from new and existing coal-, gas- and oil-based power plants. Pursuant to this agreement, EPA will propose standards for both new or modified boilers and for existing facilities by July 26, 2011, and finalize those standards by May 26, 2012. The impact of these rules on the Company is unknown at this time, but they could result in material costs.

In addition, almost half of the states, either individually or through multi state regional initiatives, have begun to consider how to address GHG emissions and are actively considering the development of emission inventories or regional GHG cap and trade programs. 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 Climate Initiative and is pursuing initiatives to reduce GHG emissions in the state. The New Mexico Environmental Improvement Board approved two separate rulemakings in November and December 2010 to limit GHG emissions from certain stationary sources. Under the November 2010 regulation, stationary sources that emit 25,000 metric tons or more of carbon dioxide a year would be required to reduce their GHG emissions by 2% per year from 2012 through 2020. The December 2010 regulation establishes a cap-and-trade system which would require certain industrial and electric generating facilities with carbon dioxide emissions in excess of 25,000 metric tons per year to reduce their emissions by 3% per year below 2010 levels. There are various uncertainties relating to these regulations, including whether current legal challenges to them will be successful, but as drafted, the Company does not expect these regulations to result in significant costs to the Company.

It is not currently possible to predict with confidence how any pending, proposed or future GHG legislation by Congress, the states, or multi-state regions or regulations adopted by EPA or the state environmental agencies will impact the Company's business. However, any such legislation or regulation of GHG emissions or any future related litigation could result in increased compliance costs or additional operating restrictions or reduced demand for the power the Company generates, could require the Company to purchase rights to emit GHG, and could have a material adverse effect on the Company's business, financial condition, reputation or results of operations.

Climate change also has potential physical effects that could be relevant to the Company's business. In particular, some studies suggest that climate change could affect our service area by causing higher temperatures, less winter precipitation and less spring runoff, as well as by causing more extreme weather events. Such developments could change the demand for power in the region and could also impact the price or ready availability of water supplies or affect maintenance needs and the reliability of Company equipment.

The Company believes that material effects on the Company's business or operations may result from the physical consequences of climate change, the regulatory approach to climate change ultimately selected and implemented by governmental authorities, or both. 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. Given the very significant remaining uncertainties regarding whether and how these issues will be regulated, as well as the timing and severity of any physical effects of climate change, the Company believes it is impossible at present to meaningfully quantify the costs of these potential impacts.

Contamination Matters. The Company has a provision for environmental remediation obligations of approximately $0.4 million at December 31, 2010, 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,		
	2010	2009	2008
Clean Air Act (1)	$ 615	$ 810	$ 584
Clean Water Act (2)	178	597	1,243

(1) Includes $0.3 million related to alleged excess emissions at the Rio Grande generating station discussed below for the twelve months ended December 31, 2009.

(2) 2009 excludes a $0.6 million adjustment reducing estimated remediation costs for a property previously owned by the Company.

The EPA has investigated releases or potential releases of hazardous substances, pollutants or contaminants at the Gila River Boundary Site, on the Gila River Indian Community ("GRIC") reservation in Arizona and designated it as a Superfund site. The Company currently owns 16.29% of the site and will share in the cost of cleanup of this site. The Company has a tentative agreement with the former property owner and in 2011, the Company is expected to enter into a consent decree with the EPA at a cost to the Company of less than $0.1 million (which amount is included in the $0.4 million accrued at December 31, 2010).

In 2006, the Company experienced an oil discharge at the Rio Grande Power Station. The Company remediated the site by removing the contaminated soil and installing monitoring wells to monitor for the presence of hydrocarbons in the ground water. The Company's abatement plan was approved by the New Mexico Environment Department, and the Company further assessed and remediated the site in accordance with the plan in 2010. The Company has incurred $0.3 million in costs related to this matter. Although monitoring of the groundwater continues in accordance with the NMED-approved abatement plan, the Company does not expect any significant additional costs to be incurred related to the 2006 discharge.

Environmental Litigation and Investigations. In May 2007, the EPA finalized a new federal implementation plan that addresses air emissions at Four Corners. APS, the Four Corners operating agent, has filed suit against the EPA relating to this new federal implementation plan to resolve issues involving operating flexibility for emission opacity standards. The Company cannot predict the outcome of the suit filed against the EPA or whether compliance with the implementation plan, as currently drafted or as amended, could have an adverse effect on its capital or operating costs.

On April 6, 2009, APS received a request from the EPA under Section 114 of the CAA seeking detailed information regarding projects and operations at Four Corners. APS has responded to this request. The Company is unable to predict the timing or content of EPA's response or any resulting actions.

On February 16, 2010, a group of environmental organizations filed a petition with the United States Departments of Interior and Agriculture requesting that the agencies certify to the EPA that emissions from Four Corners are causing "reasonably attributable visibility impairment" under the CAA. APS is currently reviewing the petition and has indicated that it will likely file a response in opposition to the petition. The Company cannot predict the outcome of the petition or whether any resulting actions could have an adverse effect on its capital or operating costs.

Lease Agreements

In February 2008, the Company purchased the executive and administrative office building in El Paso that it had previously leased. All obligations incurred under this lease were terminated. In June 2008, the Company entered into an agreement to lease land in El Paso adjacent to the Newman Power Station under a lease which expires in June 2033 with a renewal option of 25 years. In addition, the Company leases certain warehouse facilities in El Paso under a lease which expires in December 2014. The Company also has several other leases for office and parking facilities which expire within the next five years.

These 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 $1.1 million for 2010, 2009 and 2008. As of December 31, 2010, the Company's minimum future rental payments for the next five years are as follows (in thousands):

2011	$ 1,013
2012	941
2013	875
2014	843
2015	799

Union Matters

The Company has approximately 1,000 employees, 41% of whom are covered by a collective bargaining agreement. The International Brotherhood of Electrical Workers Local 960 ("Local 960") represents employees working primarily in the power plants, substations, line crews, meter reading and collection areas, facilities services area, and the customer service area. Effective September 3, 2010, the Company entered into a new collective bargaining agreement with Local 960 for a three-year term ending September 2, 2013.

K. 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.

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

L. 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 plans that are non-funded defined benefit plans. One plan covers certain former employees and directors 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 plans are based on substantially the same actuarial methods and economic assumptions as those used for the Retirement Plan. On December 15, 2009, the Company adopted FASB guidance on disclosure for pension and other post-retirement plans that requires additional disclosure of investment policies and strategies, categories of investment and fair value measurements of plan assets, and significant concentrations of risk.

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

	December 31,			
	2010		2009	
	Retirement Income Plan	Non-Qualified Retirement Plans	Retirement Income Plan	Non-Qualified Retirement Plans
Change in projected benefit obligation:				
Benefit obligation at end of prior year	$ 215,944	$ 21,767	$ 198,528	$ 20,555
Service cost	5,888	176	5,414	120
Interest cost	12,507	1,122	11,942	1,241
Amendments	0	838	0	0
Actuarial loss	16,008	1,822	6,793	1,892
Benefits paid	(7,629)	(1,717)	(6,733)	(2,041)
Benefit obligation at end of year	242,718	24,008	215,944	21,767
Change in plan assets:				
Fair value of plan assets at end of prior year	155,140	0	178,372	0
Actual return on plan assets	17,030	0	(26,299)	0
Employer contribution	6,800	1,717	9,800	2,041
Benefits paid	(7,629)	(1,717)	(6,733)	(2,041)
Fair value of plan assets at end of year	171,341	0	155,140	0
Funded status at end of year	$ (71,377)	$ (24,008)	$ (60,804)	$ (21,767)

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

	December 31,			
	2010		2009	
	Retirement Income Plan	Non-Qualified Retirement Plans	Retirement Income Plan	Non-Qualified Retirement Plans
Current liabilities	$ 0	$ (1,914)	$ 0	$ (1,631)
Noncurrent liabilities	(71,377)	(22,094)	(60,804)	(20,136)
Total	$ (71,377)	$ (24,008)	$ (60,804)	$ (21,767)

The accumulated benefit obligation for all retirement plans was $228.7 million and $202.9 million at December 31, 2010 and 2009, respectively. The accumulated benefit obligation in excess of plan assets is as follows (in thousands):

	December 31,			
	2010		2009	
	Retirement Income Plan	Non-Qualified Retirement Plans	Retirement Income Plan	Non-Qualified Retirement Plans
Projected benefit obligation	$ (242,718)	$ (24,008)	$ (215,944)	$ (21,767)
Accumulated benefit obligation	(205,167)	(23,538)	(181,837)	(21,072)
Fair value of plan assets	171,341	0	155,140	0

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

	Years Ended December 31,			
	2010		2009	
	Retirement Income Plan	Non-Qualified Retirement Plans	Retirement Income Plan	Non-Qualified Retirement Plans
Net loss	$ 95,828	$ 6,364	$ 86,315	$ 4,760
Prior service cost	46	502	68	596
Total	$ 95,874	$ 6,866	$ 86,383	$ 5,356

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

	December 31,					
	2010			2009		
		Non-Qualified			Non-Qualified	
	Retirement Income Plan	Supplemental Retirement Plan	Excess Benefit Plan	Retirement Income Plan	Supplemental Retirement Plan	Excess Benefit Plan
Discount rate	5.4%	4.6%	5.3%	5.9%	5.2%	6.0%
Rate of compensation increase	5.0%	N/A	5.0%	5.0%	N/A	5.0%

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

	Years Ended December 31,					
	2010		2009		2008	
	Retirement Income Plan	Non-Qualified Retirement Plans	Retirement Income Plan	Non-Qualified Retirement Plans	Retirement Income Plan	Non-Qualified Retirement Plans
Service cost	$ 5,888	$ 176	$ 5,414	$ 120	$ 4,958	$ 117
Interest cost	12,507	1,122	11,942	1,241	11,357	1,243
Amendments	0	838	0	0	0	0
Expected return on plan assets	(13,867)	0	(15,439)	0	(14,233)	0
Amortization of:						
Net loss	3,331	218	1,549	76	1,072	101
Prior service cost	21	94	21	94	21	94
Net periodic benefit cost	$ 7,880	$ 2,448	$ 3,487	$ 1,531	$ 3,175	$ 1,555

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

	Years Ended December 31,					
	2010		2009		2008	
	Retirement Income Plan	Non-Qualified Retirement Plans	Retirement Income Plan	Non-Qualified Retirement Plans	Retirement Income Plan	Non-Qualified Retirement Plans
Net loss	$ 12,844	$ 1,822	$ 48,531	$ 1,892	$ 15,802	$ 456
Amortization of:						
Net loss	(3,331)	(218)	(1,549)	(76)	(1,072)	(101)
Prior service cost	(21)	(94)	(21)	(94)	(21)	(94)
Total expense recognized in other comprehensive income	$ 9,492	$ 1,510	$ 46,961	$ 1,722	$ 14,709	$ 261

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

	Years Ended December 31,					
	2010		2009		2008	
	Retirement Income Plan	Non-Qualified Retirement Plans	Retirement Income Plan	Non-Qualified Retirement Plans	Retirement Income Plan	Non-Qualified Retirement Plans
Total recognized in net periodic benefit cost and other comprehensive income	$ 17,372	$ 3,958	$ 50,448	$ 3,253	$ 17,884	$ 1,816

The following are amounts in accumulated other comprehensive income that are expected to be recognized as components of net periodic benefit cost during 2011 (in thousands):

	Retirement Income Plan	Non-Qualified Retirement Plans
Net loss	$ 5,983	$ 351
Prior service cost	21	94

The following are the weighted-average actuarial assumptions used to determine the net periodic benefit cost for the twelve months ended December 31:

	2010			2009			2008		
		Non-Qualified			Non-Qualified			Non-Qualified	
	Retirement Income Plan	Retirement Plan	Excess Benefit Plan	Retirement Income Plan	Retirement Plan	Excess Benefit Plan	Retirement Income Plan	Retirement Plan	Excess Benefit Plan
Discount rate	5.9%	5.2%	6.0%	6.1%	6.3%	6.3%	6.4%	6.1%	6.4%
Expected long-term return on plan assets	7.5%	N/A	N/A	8.5%	N/A	N/A	8.5%	N/A	N/A
Rate of compensation increase	5.0%	N/A	5.0%	5.0%	N/A	5.0%	5.0%	N/A	5.0%

The Company reassesses various actuarial assumptions at least on an annual basis. The discount rate is changed at each measurement date based on projected cash flows of the benefit plans using the spot rates in the Citigroup Pension Discount Curve and then solving for a single discount rate that produces the same present value of cash flows for each plan. The Company changed its discount rate to determine the benefit obligations for the retirement income plan from 5.90% to 5.40%, the non-qualified retirement plan from 5.20% to 4.60%; and the excess benefit plan from 6.00% to 5.30% at December 31, 2010. For determining 2010 benefit costs, the Company changed its discount rate for the retirement income plan from 6.10% to 5.90%, the non-qualified retirement plan from 6.30% to 5.20% and the excess benefit plan from 6.30% to 6.00%. A 1.0% decrease in the discount rate would increase the December 31, 2010 retirement plans' projected benefit obligation by 14.8%. A 1.0% increase in the discount rate would decrease the December 31, 2010 retirement plans' projected benefit obligation by 12.1%.

The Company's overall expected long-term rate of return on assets is 7.5% effective January 1, 2010, 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 Company's target allocations for the plan's assets are 50% equity securities, 45% fixed income and 5% alternative investments. The Retirement Plan fund includes a diversified portfolio of funds investing in equity securities including large and small capital funds and international funds. The Retirement Plan fund also invests in fixed income securities and real estate. The expected returns for 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.

FASB guidance on disclosure for pension plans requires disclosure of fair value measurements of plan assets. To increase consistency and comparability in fair value measurements FASB guidance on fair value measurements established a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value into three levels as follows:

- Level 1 – Observable inputs that reflect quoted market prices for identical assets and liabilities in active markets. Prices for securities held in the underlying portfolios of the Retirement Plan are primarily obtained from independent pricing services. These prices are based on observable market data for the same or similar securities.

- Level 2 – Inputs other than quoted market prices included in Level 1 that are observable for the asset or liability either directly or indirectly. The fair value of the Guaranteed Investment Contract is based on market interest rates of investments with similar terms and risk characteristics.

- Level 3 – Unobservable inputs using data that is not corroborated by market data. The fair value of the limited real estate partnership is reported at the net asset value of the investment.

The fair value of the Company's Retirement Plan assets at December 31, 2010 and 2009, and the level within the three levels of the fair value hierarchy defined by FASB guidance on fair value measurements are presented in the table below (in thousands):

Description of Securities	Fair Value as of December 31, 2010	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Cash and Cash Equivalents	$ 4,975	$ 4,975	$ 0	$ 0
U.S. Treasury Securities	83,601	83,601	0	0
Guaranteed Investment Contract	550	0	550	0
Common Stock	54,957	54,957	0	0
Mutual Funds	19,501	19,501	0	0
Limited Partnership Interest in Real Estate (a).	7,757	0	0	7,757
Total Plan Investments	$ 171,341	$ 163,034	$ 550	$ 7,757

Description of Securities	Fair Value as of December 31, 2009	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Cash and Cash Equivalents	$ 7,011	$ 7,011	$ 0	$ 0
U.S. Treasury Securities	75,454	75,454	0	0
Guaranteed Investment Contract	570	0	570	0
Common Stock	37,839	37,839	0	0
Mutual Funds	25,978	25,978	0	0
Limited Partnership Interest in Real Estate (a)	8,288	0	0	8,288
Total Plan Investments	$ 155,140	$ 146,282	$ 570	$ 8,288

(a) This investment is a commercial real estate partnership that purchases land, develops limited infrastructure, and sells it for commercial development. The Company is restricted from selling its partnership interest during the life of the partnership which is generally 5-7 years. Return of investment is realized as land is sold. The fair value of the limited partnership interest in real estate is based on the net asset value of the partnership which reflects the appraised value of the land.

The fair value of the investment in the Limited Partnership Interest in Real Estate as of December 31, 2010 resulted in an unrealized loss of $0.5 million for the twelve months ended December 31, 2010. The table below reflects the changes during the period (in thousands):

	Fair Value of Investments in Real Estate
Balance at December 31, 2008	$ 8,932
Unrealized loss in fair value	(644)
Balance at December 31, 2009	8,288
Unrealized loss in fair value	(531)
Balance at December 31, 2010	$ 7,757

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 Company contributes at least the minimum funding amounts required by the IRS for the Retirement Plan, as actuarially calculated. The Company expects to contribute $13.9 million to its retirement plans in 2011, although the Company has no 2011 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 Plans
2011	$ 8,168	$ 1,914
2012	9,001	1,778
2013	9,885	1,737
2014	10,898	1,694
2015	11,963	1,732
2016-2020	77,566	9,286

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 currently based on the funding amounts established in PUCT Docket No. 37690. 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 guidance on 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. Effective January 1, 2011, the Medicare Part D subsidy will be included in the initial cost of prescriptions and the Company will no longer need to apply for the Medicare Part D subsidy for prescription drug claims.

In March 2010, the President signed into law comprehensive health care reform legislation under the Patient Protection and Affordable Care Act and the Health Care Education and Affordability Reconciliation Act (the "Acts"). The Company modified the operations of the plan to conform to the effective provisions of the Acts.

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,	
	2010	2009
Change in benefit obligation:		
Benefit obligation at end of prior year	$ 118,267	$ 111,036
Service cost	3,558	3,395
Interest cost	6,664	6,492
Actuarial loss	(3,807)	466
Amendments	(26,605)	0
Benefits paid	(3,598)	(3,840)
Retiree contributions	584	541
Medicare Part D subsidy	191	177
Benefit obligation at end of year	95,254	118,267
Change in plan assets:		
Fair value of plan assets at end of prior year	29,348	25,239
Actual return on plan assets	2,514	3,809
Employer contribution	4,621	3,422
Benefits paid	(3,598)	(3,840)
Retiree contributions	584	541
Medicare Part D subsidy	191	177
Fair value of plan assets at end of year	33,660	29,348
Funded status	$ (61,594)	$ (88,919)

Amounts recognized in the Company's consolidated balance sheets as a non-current liability consist of accrued postretirement costs of $61.6 million and $88.9 million for December 31, 2010 and 2009, respectively. The amendments that occurred during the twelve months ended December 31, 2010 primarily related to modifications to the required copayment levels, deductibles and out-of-pocket maximum responsibilities retained by the retired employees.

Amounts recognized in accumulated other comprehensive income that have not been recognized as a component of net periodic cost consist of the following (in thousands):

	Years Ended December 31,	
	2010	2009
Net gain	$ (14,411)	$ (9,793)
Prior service credit	(36,574)	(12,839)
	$ (50,985)	$ (22,632)

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

	December 31,	
	2010	2009
Discount rate at end of year	5.5%	5.9%
Health care cost trend rates:		
Initial	8.5%	8.5%
Ultimate	5.0%	5.0%
Year ultimate reached	2018	2017

Net periodic benefit cost is made up of the components listed below (in thousands):

	Years Ended December 31,		
	2010	2009	2008
Service cost	$ 3,558	$ 3,395	$ 3,160
Interest cost	6,664	6,492	6,199
Expected return on plan assets	(1,529)	(1,499)	(1,853)
Amortization of:			
Prior service benefit	(2,869)	(2,869)	(2,869)
Net gain	(175)	0	(1,325)
Net periodic benefit cost	$ 5,649	$ 5,519	$ 3,312

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

	Years Ended December 31,		
	2010	2009	2008
Net loss (gain)	$ (4,792)	$ (1,843)	$ 14,329
Prior service benefit	(26,605)	0	0
Amortization of:			
Prior service benefit	2,869	2,869	2,869
Net gain	175	0	1,325
Total recognized in other comprehensive income	$ (28,353)	$ 1,026	$ 18,523

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

	Years Ended December 31,		
	2010	2009	2008
Total recognized in net periodic benefit cost and other comprehensive income	$ (22,704)	$ 6,545	$ 21,835

The amounts in accumulated other comprehensive income that are expected to be recognized as a component of net periodic benefit cost during 2011 is a prior service benefit of $5.9 million and a net gain of $0.4 million.

The following are the weighted-average actuarial assumptions used to determine the net periodic benefit cost for the twelve months ended December 31:

	2010	2009	2008
Discount rate at beginning of year	5.9%	6.0%	6.5%
Expected long-term return on plan assets	5.2%	5.9%	5.9%
Health care cost trend rates:			
Initial	8.5%	9.0%	9.5%
Ultimate	5.0%	5.0%	5.0%
Year ultimate reached	2017	2017	2017

The discount rate is changed at each measurement date based on projected cash flows of the benefit plans using the spot rates in the Citigroup Pension Discount Curve and then solving for a single discount rate that produces the same present value of cash flows for each plan. At December 31, 2010, the Company changed its discount rate from 5.90% to 5.50% to determine the benefit obligations for the other postretirement benefits plan. For determining 2010 benefit cost, the Company changed its discount rate from 6.00% to 5.90%. A 1.0% decrease in the discount rate would increase the December 31, 2010 accumulated postretirement benefit obligation by 16.5%. A 1.0% increase in the discount rate would decrease the December 31, 2010 accumulated postretirement benefit obligation by 13.1%.

For measurement purposes, a 8.5% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2010. 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 December 31, 2010 benefit obligation by $15.2 million or $12.3 million, respectively. In addition, such a 1% change would increase or decrease the aggregate 2010 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 5.2% effective January 1, 2010. 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 Company's target allocations for the plan's assets are 65% equity securities, 30% fixed income and 5% alternative investments. The asset portfolio includes a diversified mix of funds investing in equity securities including large and small capital funds and international funds. The asset portfolio also includes fixed income securities, cash equivalents, and real estate. The expected returns for 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.

FASB guidance on disclosure for other postretirement plans requires disclosure of fair value measurements of plan assets. To increase consistency and comparability in fair value measurements FASB guidance on fair value measurements established a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value into three levels as follows:

- Level 1 – Observable inputs that reflect quoted market prices for identical assets and liabilities in active markets. Prices for securities held in the underlying portfolios of the Other Postretirement Benefits Plan are primarily obtained from independent pricing services. These prices are based on observable market data for the same or similar securities.

- Level 2 – Inputs other than quoted market prices included in Level 1 that are observable for the asset or liability either directly or indirectly. The fair value of municipal securities – tax-exempt are reported at fair value based on evaluated prices that reflect observable market information, such as actual trade information of similar securities, adjusted for observable differences.

- Level 3 – Unobservable inputs using data that is not corroborated by market data. The fair value of the limited real estate partnership is reported at the net asset value of the investment.

The fair value of the Company's Other Postretirement Benefits Plan assets at December 31, 2010 and 2009, and the level within the three levels of the fair value hierarchy defined by FASB guidance on fair value measurements are presented in the table below (in thousands):

Description of Securities	Fair Value as of December 31, 2010	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Cash and Cash Equivalents	$ 4,122	$ 4,122	$ 0	$ 0
Municipal Securities – Tax Exempt	11,348	0	11,348	0
Common Stock	16,735	16,735	0	0
Limited Partnership Interest in Real Estate (a).	1,455	0	0	1,455
Total Plan Investments	$ 33,660	$ 20,857	$ 11,348	$ 1,455

Description of Securities	Fair Value as of December 31, 2009	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Cash and Cash Equivalents	$ 2,566	$ 2,566	$ 0	$ 0
Municipal Securities – Tax Exempt	10,928	0	10,928	0
Common Stock	14,300	14,300	0	0
Limited Partnership Interest in Real Estate (a).	1,554	0	0	1,554
Total Plan Investments	$ 29,348	$ 16,866	$ 10,928	$ 1,554

(a) This investment is a commercial real estate partnership that purchases land, develops limited infrastructure, and sells it for commercial development. The Company is restricted from selling its partnership interest during the life of the partnership which is generally 5-7 years. Return of investment is realized as land is sold. The fair value of the limited partnership interest in real estate is based on the net asset value of the partnership which reflects the appraised value of the land.

The fair value of the investment in the Limited Partnership Interest in Real Estate as of December 31, 2010 resulted in an unrealized loss of $0.1 million for the twelve months ended December 31, 2010. The table below reflects the changes during the period (in thousands):

	Fair Value of Investments in Real Estate
Balance at December 31, 2008	$ 1,675
Unrealized loss in fair value	(121)
Balance at December 31, 2009	1,554
Unrealized loss in fair value	(99)
Balance at December 31, 2010	$ 1,455

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 $2.2 million to its other postretirement benefits plan in 2011.

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid (in thousands):

2011	$ 2,944
2012	3,388
2013	3,826
2014	4,278
2015	4,767
2016-2020	30,031

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. Annual matching contributions made to the savings plans for the years 2010, 2009 and 2008 were $1.7 million, $1.6 million, and $1.6 million, respectively.

Annual Short-Term Incentive Plan

The Annual Short-Term Incentive Plan (the "Incentive 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, regulatory compliance, and customer satisfaction. If a specified level of earnings per share is not attained, no amounts will be paid under the Incentive Plan. The Company reached the required levels of earnings per share, safety, and regulatory compliance goals for an incentive payment of $7.4 million in 2010. In 2009 and 2008, the Company reached the required levels of earnings per share, customer satisfaction, and safety goals for an incentive payment of $8.6 million and $5.2 million, respectively. The Company has renewed the Incentive Plan in 2011 with similar goals.

M. 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, entered into in July 2005, included a franchise fee of 3.25% of revenues. Effective August 2010, the franchise fee was increased to 4%. The additional fee of 0.75% is to be placed in a restricted fund to be used solely for economic development and renewable energy purposes. The franchise agreement 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 for the provision of electric distribution service. Las Cruces exercised its right to extend the franchise for an additional two-year term which ended April 30, 2009 and waived its option to purchase the Company's distribution system pursuant to the terms of the February 2000 settlement agreement. The Company is currently operating under an implied franchise by satisfying all obligations under the expired franchise.

Military Installations

The Company currently serves Holloman Air Force Base ("Holloman"), White Sands Missile Range ("White Sands") and Fort Bliss. The Company's sales to the military bases represent approximately 4% of annual retail revenues. The Company signed a contract with Ft. Bliss in October 2008 under which Ft. Bliss takes retail electric service from the Company. The contract with Ft. Bliss expired in 2010 and the Company is serving Ft. Bliss under the applicable Texas tariffs. In April 1999, the Army and the Company entered into a ten-year contract to provide retail electric service to White Sands. The contract with White Sands expired in 2009 and the Company is serving White Sands under the applicable New Mexico tariffs. 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.

N. Financial Instruments and Investments

FASB guidance 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. Investments in debt securities and decommissioning trust funds are carried at fair value.

Long-Term Debt and Financing Obligations. 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,			
	2010		2009	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Pollution Control Bonds	$ 193,135	$ 192,924	$ 193,135	$ 197,680
Senior Notes	546,610	574,700	546,562	545,475
Nuclear Fuel Financing (1):				
RGRT Senior Notes	110,000	110,371	0	0
RCF	4,704	4,704	106,998	106,998
Total	$ 854,449	$ 882,699	$ 846,695	$ 850,153

(1) Nuclear fuel financing as of December 31, 2010 is funded through the $110 million RGRT Senior Notes and the RCF. See Note H. The interest rate on the Company's nuclear fuel financing through the RCF is reset every quarter to reflect current market rates. Consequently, the carrying value approximates fair value.

Treasury Rate Locks. The Company entered into treasury rate lock agreements in 2005 to hedge against potential movements in the treasury reference interest rate pending the issuance of the 6% Senior Notes. 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, net of tax, as a component of accumulated other comprehensive loss and amortizes the accumulated comprehensive loss to earnings as interest expense over the life of the 6% Senior Notes. In 2011, approximately $0.4 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, 2010, 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 FASB guidance for accounting for derivative instruments and hedging activities, and, as such, were not required to be accounted for as derivatives.

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 FASB guidance for accounting for derivative instruments and hedging activities. However, as of December 31, 2010, 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 $153.9 million and $135.4 million at December 31, 2010 and 2009, respectively. These securities are classified as available for sale under FASB guidance for certain investments in debt and equity securities and are valued using prices and other relevant information generated by market transactions involving identical or comparable securities. The reported fair values include gross unrealized losses on marketable securities whose impairment the Company has deemed to be temporary. The tables below present the gross unrealized losses and the fair value of these securities, aggregated by investment category and length of time that individual securities have been in a continuous unrealized loss position (in thousands):

	December 31, 2010					
	Less than 12 Months		12 Months or Longer		Total	
	Fair Value	Unrealized Losses	Fair Value	Unrealized Losses	Fair Value	Unrealized Losses
Description of Securities (1):						
Federal Agency Mortgage Backed Securities	$ 2,290	$ (51)	$ 441	$ (27)	$ 2,731	$ (78)
U.S. Government Bonds	9,583	(124)	0	0	9,583	(124)
Municipal Obligations	13,145	(278)	3,763	(145)	16,908	(423)
Corporate Obligations	1,855	(18)	0	0	1,855	(18)
Total debt securities	26,873	(471)	4,204	(172)	31,077	(643)
Common stock	6,943	(774)	4,303	(420)	11,246	(1,194)
Total temporarily impaired securities	$ 33,816	$ (1,245)	$ 8,507	$ (592)	$ 42,323	$ (1,837)

(1) Includes approximately 96 securities.

	December 31, 2009					
	Less than 12 Months		12 Months or Longer		Total	
	Fair Value	Unrealized Losses	Fair Value	Unrealized Losses	Fair Value	Unrealized Losses
Description of Securities (2):						
Federal Agency Mortgage Backed Securities	$ 6,975	$ (70)	$ 38	$ (2)	$ 7,013	$ (72)
U.S. Government Bonds	9,355	(248)	0	0	9,355	(248)
Municipal Obligations	3,235	(53)	5,067	(159)	8,302	(212)
Corporate Obligations	2,039	(20)	856	(27)	2,895	(47)
Total debt securities	21,604	(391)	5,961	(188)	27,565	(579)
Common stock	11,735	(790)	3,718	(686)	15,453	(1,476)
Total temporarily impaired securities	$ 33,339	$ (1,181)	$ 9,679	$ (874)	$ 43,018	$ (2,055)

(2) Includes approximately 106 securities.

The Company monitors the length of time the security 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 securities until their market price recovers, these securities are considered 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.

The reported fair values also include gross unrealized gains on marketable securities which have not been recognized in the Company's net income. The table below presents the unrecognized gross unrealized gains and the fair value of these securities, aggregated by investment category (in thousands):

	December 31, 2010		December 31, 2009	
	Fair Value	Unrealized Gains	Fair Value	Unrealized Gains
Description of Securities:				
Federal Agency Mortgage Backed Securities	$ 18,472	$ 793	$ 13,050	$ 567
U.S. Government Bonds	10,450	183	4,537	58
Municipal Obligations	15,633	592	21,121	852
Corporate Obligations	7,223	362	4,313	222
Total debt securities	51,778	1,930	43,021	1,699
Common stock	56,770	14,142	45,317	7,808
Temporary investments	3,007	0	4,016	0
Total	$111,555	$ 16,072	$ 92,354	$ 9,507

The Company's marketable securities include investments in municipal, corporate and federal debt obligations. Substantially all of the Company's mortgage backed securities, based on contractual maturity, are due in 10 years or more. The mortgage backed securities have an estimated weighted average maturity which generally range from 3 to 7 years and reflects anticipated future prepayments. The contractual year for maturity for all other available-for-sale securities as of December 31, 2010 is as follows (in thousands):

	Total	2011	2012 through 2015	2016 through 2020	2021 and Beyond
Municipal Debt Obligations	$ 32,541	$ 2,314	$ 11,338	$ 11,911	$ 6,978
Corporate Debt Obligations	9,077	0	4,023	3,306	1,748
U.S. Government Bonds	20,033	2,360	8,157	6,556	2,960

The Company recognizes impairment losses on certain of its securities deemed to be other than temporary. In accordance with FASB guidance, these impairment losses are recognized in net income, and a lower cost basis is established for these securities. For the twelve months ended December 31, 2010, 2009, and 2008 the Company recognized other than temporary impairment losses on its available-for-sale securities as follows (in thousands):

	2010	2009	2008
Gross unrealized holding losses included in pre-tax income	$ (263)	$ (5,594)	$ (7,761)

The Company's marketable securities in its decommissioning trust funds are sold from time to time, and the Company uses the specific identification basis on which to determine the amount to reclassify out of accumulated other comprehensive income and into net income. The proceeds from the sale of these securities during the twelve months ended December 31, 2010, 2009, and 2008 and the related effects on pre-tax income are as follows (in thousands):

	2010	2009	2008
Proceeds from sales of available-for-sale securities	$ 61,656	$ 79,935	$ 53,447
Gross realized gains included in pre-tax income	$ 1,030	$ 3,614	$ 5,505
Gross realized losses included in pre-tax income	(889)	(238)	(620)
Gross unrealized losses included in pre-tax income	(263)	(5,594)	(7,761)
Net losses in pre-tax income	$ (122)	$ (2,218)	$ (2,876)
Net unrealized holding gains (losses) included in accumulated other comprehensive income	$ 6,665	$ 12,816	$ (29,779)
Net losses reclassified out of accumulated other comprehensive income	122	2,218	2,876
Net gains (losses) in other comprehensive income	$ 6,787	$ 15,034	$ (26,903)

Fair Value Measurements. FASB guidance requires the Company to provide expanded quantitative disclosures for financial assets and liabilities recorded on the balance sheet at fair value. Financial assets carried at fair value include the Company's decommissioning trust investments and investments in debt securities. The Company has no liabilities that are measured at fair value on a recurring basis. The FASB guidance establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value into three levels as follows:

- Level 1 – Observable inputs that reflect quoted market prices for identical assets and liabilities in active markets. Financial assets utilizing Level 1 inputs include the nuclear decommissioning trust investments in active exchange-traded equity securities and U.S. treasury securities that are in a highly liquid and active market.

- Level 2 – Inputs other than quoted market prices included in Level 1 that are observable for the asset or liability either directly or indirectly. Financial assets utilizing Level 2 inputs include the nuclear decommissioning trust investments in fixed income securities other than U.S. Treasury securities. The fair value of these financial instruments is based on evaluated prices that reflect observable market information, such as actual trade information of similar securities, adjusted for observable differences.

- Level 3 – Unobservable inputs using data that is not corroborated by market data and primarily based on internal Company analysis using models and various other analyses. Financial assets utilizing Level 3 inputs include the Company's investments in debt securities.

As of December 31, 2010, the Company had $4.0 million invested in debt securities which consisted of two $2.0 million investments in auction rate securities maturing in 2042 and 2044. The Company classifies these securities as trading securities which are included in deferred charges and other assets on the Company's consolidated balance sheets. These auction rate securities are collateralized with student loans which are re-insured by the Department of Education as part of the Federal Family Education Loan Program ("FFELP") and have credit ratings of "A" by Standard & Poor's and "A2" by Moody's. The principal on the securities can be realized at maturity, sold in a successful auction, or sold in the secondary market. Interest rates on the auction rate securities are reset every 28 days. At December 31, 2010 upon a failed auction, the maximum interest rate for $2.0 million of these debt securities was based upon the lesser of the interest paid on the student loan portfolio, less service costs, or one-month LIBOR plus 2.5%. At December 31, 2010, the default interest rate was 2.76% based on one-month LIBOR plus 2.5%. The maximum interest rate for the remaining $2.0 million of debt securities was based upon the lesser of (i) the net loan rate (the interest paid on the student loan portfolio less service costs); (ii) 91-day Treasury bills plus 1.5%; (iii) one-month LIBOR plus 1.5%; (iv) 18%; or (v) highest rate legally payable. At December 31, 2010, the default interest rate was 1.45% based on the net loan rate.

The auction process historically provided a liquid market to sell the securities to meet cash requirements. These auction rate securities had successful auctions through January 2008. However, since February 2008, auctions for these securities have not been successful, resulting in the inability to liquidate these investments. The Company's valuation as of December 31, 2010 is based upon the average of a discounted cash flow model valuation and a market comparables method.

The discounted cash flow model valuation is based on expected cash flows using the maximum expected interest rates discounted by an expected yield reflecting illiquidity and credit risk. In order to more accurately forecast cash flows, Treasury and LIBOR yield curves were created using swap rates and data provided on the U.S. Department of the Treasury website and the British Banker's Association website. After thorough analysis, future cash flows were projected based on interest rate models over a term, which was based on an estimate of the weighted average life of the student loan portfolio within the issuing trusts. The applied discount yield was based on the applicable forward LIBOR rate and a yield spread of 390 and 400 basis points based on each security's (i) credit risk, (ii) illiquidity, (iii) subordinated status, (iv) interest rate limitations, and (v) FFELP guarantees.

The market comparables method is based upon sales and purchases of auction rate securities in secondary market transactions. The secondary market discounts of 24% to 32% are based on discounts indicated in secondary market transactions involving comparable student loan auction rate securities. The average of the values provided by the discounted cash flow calculation and the market comparables method are used to arrive at the concluded value of the securities.

The securities in the Company's decommissioning trust funds are valued using prices and other relevant information generated by market transactions involving identical or comparable securities. FASB guidance identifies this valuation technique as the "market approach" with observable inputs. The Company analyzes available-for-sale securities to determine if losses are other than temporary.

The fair value of the Company's decommissioning trust funds and investments in debt securities, at December 31, 2010 and 2009, and the level within the three levels of the fair value hierarchy defined by FASB guidance are presented in the table below (in thousands):

Description of Securities	Fair Value as of December 31, 2010	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Trading Securities:				
Investments in Debt Securities	$ 2,909	$ 0	$ 0	$ 2,909
Available for sale:				
U.S. Government Bonds	$ 20,033	$ 20,033	$ 0	$ 0
Federal Agency Mortgage Backed Securities	21,204	0	21,204	0
Municipal Bonds	32,541	0	32,541	0
Corporate Asset Backed Obligations	9,077	0	9,077	0
Subtotal, Debt Securities	82,855	20,033	62,822	0
Common Stock	68,016	68,016	0	0
Cash and Cash Equivalents	3,007	3,007	0	0
Total available for sale	$ 153,878	$ 91,056	$ 62,822	$ 0

Description of Securities	Fair Value as of December 31, 2009	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Trading Securities:				
Investments in Debt Securities	$ 2,510	$ 0	$ 0	$ 2,510
Available for sale:				
U.S. Government Bonds	$ 13,892	$ 13,892	$ 0	$ 0
Federal Agency Mortgage Backed Securities	20,063	0	20,063	0
Municipal Bonds	29,424	0	29,424	0
Corporate Asset Backed Obligations	7,207	0	7,207	0
Subtotal, Debt Securities	70,586	13,892	56,694	0
Common Stock	60,770	60,770	0	0
Cash and Cash Equivalents	4,016	4,016	0	0
Total available for sale	$ 135,372	$ 78,678	$ 56,694	$ 0

The change in the fair value of the investments in debt securities resulted in a credit to income of $0.4 million and $0.2 million for the twelve months ended December 31, 2010 and 2009, respectively. These amounts are reflected in the Company's consolidated statement of operations as an adjustment to investment and interest income. Below is a reconciliation of the beginning and ending balance of the fair value in investment in debt securities (in thousands):

	2010	2009
Balance at January 1	$ 2,510	$ 2,264
Unrealized gain in fair value recognized in income	399	246
Balance at December 31	$ 2,909	$ 2,510

O. Supplemental Statements of Cash Flows Disclosures

	Years Ended December 31,		
	2010	2009	2008
		(In thousands)	
Cash paid for:			
Interest on long-term debt and financing obligations	$ 47,783	$ 46,836	$ 41,909
Income taxes	7,343	8,596	4,353
Other interest	0	4	196
Non-cash financing activities:			
Grants of restricted shares of common stock	2,098	1,592	3,021
Issuance of performance shares	662	0	757

P. Selected Quarterly Financial Data (Unaudited)

The following table summarizes the Company's unaudited results of operations on a quarterly basis. The quarterly earnings per share amounts for a year will not add to the earnings per share for that year due to the weighting of shares used in calculating per share data.

	2010 Quarters				2009 Quarters			
	4th	3rd	2nd	1st	4th	3rd	2nd	1st
	(In thousands except for share data)							
Operating revenues (1)	$ 181,344	$ 280,342	$211,397	$204,168	$ 193,013	$ 240,898	$203,649	$190,436
Operating income	13,784	84,098	40,477	30,603	14,981	59,094	33,216	25,874
Income before extraordinary gain	7,466	49,896	21,507	11,449	7,961	33,932	15,431	9,609
Extraordinary gain related to Texas regulatory assets, net of tax	0	10,286	0	0	0	0	0	0
Net income	7,466	60,182	21,507	11,449	7,961	33,932	15,431	9,609
Basic earnings per share:								
Income before extraordinary gain	0.18	1.16	0.49	0.26	0.18	0.76	0.34	0.21
Extraordinary gain related to Texas regulatory assets, net of tax	0.00	0.24	0.00	0.00	0.00	0.00	0.00	0.00
Net income	0.18	1.40	0.49	0.26	0.18	0.76	0.34	0.21
Diluted earnings per share:								
Income before extraordinary gain	0.17	1.15	0.49	0.26	0.18	0.76	0.34	0.21
Extraordinary gain related to Texas regulatory assets, net of tax	0.00	0.24	0.00	0.00	0.00	0.00	0.00	0.00
Net income	0.17	1.39	0.49	0.26	0.18	0.76	0.34	0.21

(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.

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. Under the supervision and with the participation of our management, including our chief executive officer and our chief financial officer, we conducted an evaluation pursuant to Rule 13a-15(b) under the Securities Exchange Act of 1934 of our disclosure controls and procedures as defined in Rule 13a-15(e) under the Securities and Exchange act of 1934. Based on that evaluation, our chief executive officer and our chief financial officer concluded that, as of December 31, 2010, our disclosure controls and procedures are effective.

Management's Annual Report on Internal Control Over Financial Reporting. Management's Annual Report on Internal Control over Financial Reporting is included herein under the caption "Management Report on Internal Control Over Financial Reporting" on page 55 of this report.

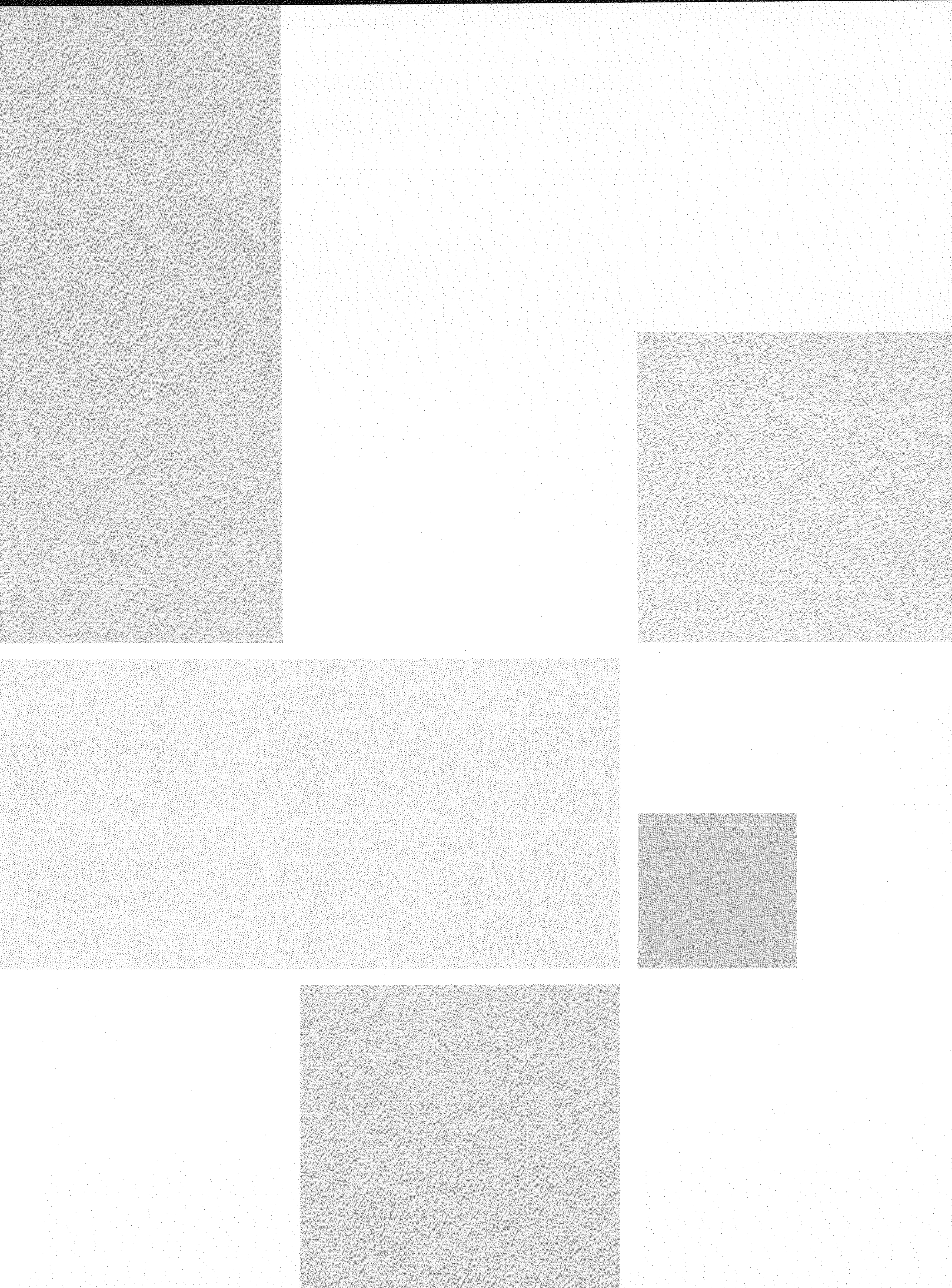
Changes in internal control over financial reporting. There were no changes in our internal control over financial reporting in connection with the evaluation required by paragraph (d) of the Securities Exchange Act of 1934 Rules 13a-15 or 15d-15, that occurred during the quarter ended December 31, 2010, that materially affected, or that were reasonably likely to materially affect, our internal control over financial reporting.

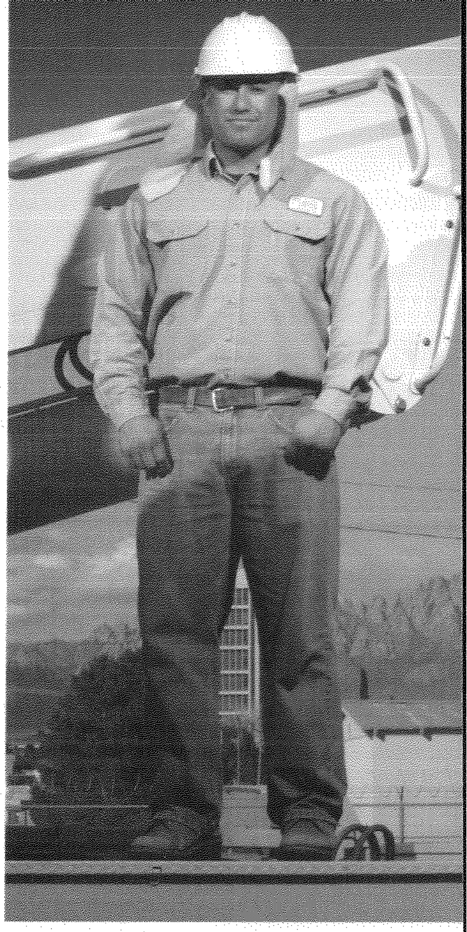
Item 9B. Other Information

None.

PART III and PART IV

The information set forth in Part III and Part IV has been omitted from this Annual Report to Shareholders.





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