EL PASO ELECTRIC CO /TX/
Form 10-Q
November 07, 2011
Table of Contents

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

Form 10-Q
(Mark One)

x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended September 30, 2011

OR

o 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)

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

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 o

Indicate by check mark whether the registrant submitted electronically and posted on its corporate Web site, 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 o

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 definitions of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	x	Accelerated filer	o
Non-accelerated filer	o	Smaller reporting company	o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). YES o NO x

As of October 31, 2011, there were 40,250,233 shares of the Company's no par value common stock outstanding.

Table of Contents

EL PASO ELECTRIC COMPANY AND SUBSIDIARY
INDEX TO FORM 10-Q

Table of Contents

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

EL PASO ELECTRIC COMPANY AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS

	September 30, 2011 (Unaudited)	December 31, 2010
ASSETS		
(In thousands)		
Utility plant:		
Electric plant in service	$2,758,648	$2,522,862
Less accumulated depreciation and amortization	(1,105,527)	(1,047,498)
Net plant in service	1,653,121	1,475,364
Construction work in progress	143,645	285,086
Nuclear fuel; includes fuel in process of $43,443 and $47,746, respectively	175,048	150,774
Less accumulated amortization	(61,140)	(45,471)
Net nuclear fuel	113,908	105,303
Net utility plant	1,910,674	1,865,753
Current assets:		
Cash and cash equivalents	7,744	79,184
Accounts receivable, principally trade, net of allowance for doubtful accounts of $2,799 and $2,885, respectively	115,395	71,685
Accumulated deferred income taxes	10,777	25,818
Inventories, at cost	39,283	36,132
Income taxes receivable	6,252	12,656
Undercollection of fuel revenues	12,275	—
Prepayments and other	7,975	4,543
Total current assets	199,701	230,018
Deferred charges and other assets:		
Decommissioning trust funds	158,437	153,878
Regulatory assets	88,894	88,557
Other	27,743	26,560
Total deferred charges and other assets	275,074	268,995
Total assets	$2,385,449	$2,364,766

See accompanying notes to consolidated financial statements.

Table of Contents

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

	September 30, 2011 (Unaudited)	December 31, 2010
CAPITALIZATION AND LIABILITIES		
(In thousands except for share data)		
Capitalization:		
Common stock, stated value $1 per share, 100,000,000 shares authorized, 65,264,664 and 65,121,689 shares issued, and 196,954 and 143,371 restricted shares, respectively	$65,462	$65,265
Capital in excess of stated value	308,138	305,068
Retained earnings	890,529	810,858
Accumulated other comprehensive income (loss), net of tax	(35,864)	(33,177)
	1,228,265	1,148,014
Treasury stock, 25,212,530 and 22,693,995 shares, respectively, at cost	(415,413)	(337,639)
Common stock equity	812,852	810,375
Long-term debt	816,484	849,745
Total capitalization	1,629,336	1,660,120
Current liabilities:		
Current maturities of long-term debt	33,300	—
Short-term borrowings under the revolving credit facility	17,793	4,704
Accounts payable, principally trade	49,653	41,795
Taxes accrued	36,033	29,172
Interest accrued	13,177	12,099
Overcollection of fuel revenues	1,643	18,976
Other	35,419	24,207
Total current liabilities	187,018	130,953
Deferred credits and other liabilities:		
Accumulated deferred income taxes	321,247	286,730
Accrued pension liability	85,149	93,471
Asset retirement obligation	54,944	92,911
Accrued postretirement benefit liability	64,357	61,594
Regulatory liabilities	15,283	14,489
Other	28,115	24,498
Total deferred credits and other liabilities	569,095	573,693
Commitments and contingencies		
Total capitalization and liabilities	$2,385,449	$2,364,766

See accompanying notes to consolidated financial statements.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Operating revenues	$307,633	$280,342	$726,350	$695,907
Energy expenses:				

Fuel	73,034	60,294	177,111	160,139
Purchased and interchanged power	25,845	28,229	60,616	76,628
	98,879	88,523	237,727	236,767
Operating revenues net of energy expenses	208,754	191,819	488,623	459,140
Other operating expenses:				
Other operations	56,832	59,924	168,148	161,566
Maintenance	12,764	10,987	41,760	41,222
Depreciation and amortization	20,315	20,685	60,775	60,136
Taxes other than income taxes	16,628	16,125	43,131	41,038
	106,539	107,721	313,814	303,962
Operating income	102,215	84,098	174,809	155,178
Other income (deductions):				
Allowance for equity funds used during construction	1,379	2,398	6,441	7,645
Investment and interest income, net	618	1,351	4,593	3,289
Miscellaneous non-operating income	113	248	384	401
Miscellaneous non-operating deductions	(648)	(389)	(2,061)	(1,277)
	1,462	3,608	9,357	10,058
Interest charges (credits):				
Interest on long-term debt and revolving credit facility	13,571	12,936	40,595	37,378
Other interest	243	48	777	113
Capitalized interest	(1,318)	(796)	(3,864)	(1,282)
Allowance for borrowed funds used during construction	(808)	(1,550)	(3,837)	(4,651)
	11,688	10,638	33,671	31,558
Income before income taxes and extraordinary item	91,989	77,068	150,495	133,678
Income tax expense	33,668	27,172	52,409	50,826
Income before extraordinary item	58,321	49,896	98,086	82,852
Extraordinary gain related to Texas regulatory assets, net of tax	—	10,286	—	10,286
Net income	$58,321	$60,182	$98,086	$93,138
Basic earnings per share:				
Income before extraordinary item	$1.41	$1.16	$2.33	$1.90
Extraordinary gain related to Texas regulatory assets, net of tax	—	0.24	—	0.24
Net income	$1.41	$1.40	$2.33	$2.14
Diluted earnings per share:				
Income before extraordinary item	$1.40	$1.15	$2.32	$1.89
Extraordinary gain related to Texas regulatory assets, net of tax	—	0.24	—	0.24
Net income	$1.40	$1.39	$2.32	$2.13
Dividends declared per share of common stock	$0.22	$—	$0.44	$—
Weighted average number of shares outstanding	41,307,632	42,921,044	41,819,428	43,370,487
Weighted average number of shares and dilutive potential shares outstanding	41,564,973	43,103,698	42,051,307	43,505,434

See accompanying notes to consolidated financial statements.

Table of Contents

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

	Twelve Months Ended September 30,	
	2011	2010
Operating revenues	$907,694	$888,920
Energy expenses:		
Fuel	216,801	205,849
Purchased and interchanged power	75,904	99,660
	292,705	305,509
Operating revenues net of energy expenses	614,989	583,411
Other operating expenses:		
Other operations	230,803	222,466
Maintenance	57,361	58,872
Depreciation and amortization	81,650	79,501
Taxes other than income taxes	56,582	52,413
	426,396	413,252
Operating income	188,593	170,159
Other income (deductions):		
Allowance for equity funds used during construction	9,612	9,575
Investment and interest income, net	6,619	7,333
Miscellaneous non-operating income	1,351	423
Miscellaneous non-operating deductions	(3,990)	(1,866)
	13,592	15,465
Interest charges (credits):		
Interest on long-term debt and revolving credit facility	54,043	49,576
Other interest	918	190
Capitalized interest	(5,069)	(1,504)
Allowance for borrowed funds used during construction	(5,857)	(5,910)
	44,035	42,352
Income before income taxes and extraordinary item	158,150	143,272
Income tax expense	52,599	52,459
Income before extraordinary item	105,551	90,813
Extraordinary gain related to Texas regulatory assets, net of tax	—	10,286
Net income	$105,551	$101,099
Basic earnings per share:		
Income before extraordinary item	$2.50	$2.07
Extraordinary gain related to Texas regulatory assets, net of tax	—	0.24
Net income	$2.50	$2.31
Diluted earnings per share:		
Income before extraordinary item	$2.49	$2.07
Extraordinary gain related to Texas regulatory assets, net of tax	—	0.24
Net income	$2.49	$2.31
Dividends declared per share of common stock	$0.44	$—

Weighted average number of shares outstanding	41,969,628	43,523,270
Weighted average number of shares and dilutive potential shares outstanding	42,207,012	43,672,324

See accompanying notes to consolidated financial statements.

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

	Three Months Ended September 30,		Nine Months Ended September 30,		Twelve Months Ended September 30,	
	2011	2010	2011	2010	2011	2010
Net income	$58,321	$60,182	$98,086	$93,138	$105,551	$101,099
Other comprehensive income (loss):						
Unrecognized pension and postretirement benefit costs:						
Net loss arising during period	—	—	—	—	(9,874)	(48,580)
Prior service benefit	—	—	—	—	26,605	—
Reclassification adjustments included in net income for amortization of:						
Prior service benefit	(1,453)	(688)	(4,358)	(2,065)	(5,047)	(2,754)
Net loss	1,625	843	4,878	2,530	5,722	2,936
Net unrealized gains (losses) on marketable securities:						
Net holding gains (losses) arising during period	(7,503)	7,019	(4,914)	3,041	(1,290)	4,619
Reclassification adjustments for net (gains) losses included in net income	1,284	193	1,081	602	601	(2,246)
Net losses on cash flow hedges:						
Reclassification adjustment for interest expense included in net income	93	86	269	252	355	333
Total other comprehensive income (loss) before income taxes	(5,954)	7,453	(3,044)	4,360	17,072	(45,692)
Income tax benefit (expense) related to items of other comprehensive income (loss):						
Unrecognized pension and postretirement benefit costs	(65)	(57)	(196)	(169)	(6,314)	16,481
Net unrealized gains (losses) on marketable securities	1,171	(1,443)	654	(729)	26	(475)
Losses on cash flow hedges	(35)	(31)	(101)	(91)	(132)	(121)
Total income tax benefit (expense)	1,071	(1,531)	357	(989)	(6,420)	15,885
Other comprehensive income (loss), net of tax	(4,883)	5,922	(2,687)	3,371	10,652	(29,807)
Comprehensive income	$53,438	$66,104	$95,399	$96,509	$116,203	$71,292

See accompanying notes to consolidated financial statements.

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

Nine Months Ended

	September 30, 2011	2010
Cash flows from operating activities:		
Net income	$98,086	$93,138
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization of electric plant in service	60,775	60,136
Amortization of nuclear fuel	28,004	22,877
Extraordinary gain related to Texas regulatory assets, net of tax	—	(10,286)
Deferred income taxes, net	46,338	17,088
Allowance for equity funds used during construction	(6,441)	(7,645)
Other amortization and accretion	15,771	12,957
Other operating activities	1,104	(488)
Change in:		
Accounts receivable	(43,710)	(42,661)
Inventories	(3,367)	(6)
Net undercollection of fuel revenues	(29,608)	(1,322)
Prepayments and other	(4,718)	(1,996)
Accounts payable	9,500	(11,733)
Taxes accrued	13,265	33,978
Interest accrued	1,078	2,338
Other current liabilities	(1,279)	1,406
Deferred charges and credits	(5,923)	(4,177)
Net cash provided by operating activities	178,875	163,604
Cash flows from investing activities:		
Cash additions to utility property, plant and equipment	(129,651)	(124,839)
Cash additions to nuclear fuel	(33,925)	(33,889)
Capitalized interest and AFUDC:		
Utility property, plant and equipment	(10,278)	(12,296)
Nuclear fuel	(3,864)	(1,282)
Allowance for equity funds used during construction	6,441	7,645
Decommissioning trust funds:		
Purchases, including funding of $6.4 and $6.2 million, respectively	(77,314)	(55,207)
Sales and maturities	67,841	46,936
Other investing activities	636	56
Net cash used for investing activities	(180,114)	(172,876)
Cash flows from financing activities:		
Repurchases of common stock	(64,783)	(30,217)
Dividends paid	(18,415)	—
Borrowings under the revolving credit facility:		
Proceeds	88,723	37,810
Payments	(75,634)	(130,708)
Proceeds from issuance of long-term debt	—	110,000
Other financing activities	(92)	(2,455)
Net cash used for financing activities	(70,201)	(15,570)
Net decrease in cash and cash equivalents	(71,440)	(24,842)
Cash and cash equivalents at beginning of period	79,184	91,790
Cash and cash equivalents at end of period	$7,744	$66,948

See accompanying notes to consolidated financial statements.

Table of Contents

EL PASO ELECTRIC COMPANY AND SUBSIDIARY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

A. Principles of Preparation

These condensed consolidated financial statements should be read in conjunction with the consolidated financial statements and notes thereto in the Annual Report of El Paso Electric Company on Form 10-K for the year ended December 31, 2010 (the “2010 Form 10-K”). Capitalized terms used in this report and not defined herein have the meaning ascribed for such terms in the 2010 Form 10-K. In the opinion of the Company’s management, the accompanying consolidated financial statements contain all adjustments necessary to present fairly the financial position of the Company at September 30, 2011 and December 31, 2010; the results of its operations and comprehensive operations for the three, nine and twelve months ended September 30, 2011 and 2010; and its cash flows for the nine months ended September 30, 2011 and 2010. The results of operations and comprehensive operations for the three and nine months ended September 30, 2011 and the cash flows for the nine months ended September 30, 2011 are not necessarily indicative of the results to be expected for the full calendar year.

Pursuant to the rules and regulations of the Securities and Exchange Commission (“SEC”), certain financial information has been condensed and certain footnote disclosures have been omitted. Such information and disclosures are normally included in financial statements prepared in accordance with generally accepted accounting principles. Certain prior period amounts have been reclassified to conform to the current period presentation.

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.

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. Accrued unbilled revenues included in accounts receivable are presented below (in thousands):

	September 30, 2011	December 31, 2010
Accrued unbilled revenues	$22,985	$16,644

The Company presents revenues net of sales taxes in its consolidated statements of operations.

Extraordinary Item. As a regulated electric utility, the Company prepares its financial statements in accordance with the FASB guidance for regulated operations. 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 its customers or refunded to its customers. In the final order for 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 its 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, in its statements of operations for the quarter ended September 30, 2010 as noted below (in thousands):

Extraordinary gain, net of income tax expense	$10,286
Income tax expense related to extraordinary gain	5,769

This item was recorded as a regulatory asset at 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.

Supplemental Cash Flow Disclosures (in thousands)

	Nine Months Ended September 30,	
	2011	2010
Cash paid for:		
Interest on long-term debt and borrowing under the revolving credit facility	$34,110	$33,474
Income taxes paid (refund)	(3,031)	5,778
Non-cash financing activities:		
Grants of restricted shares of common stock	3,231	2,057
Issuance of performance shares	628	662
Acquisition of treasury stock for options exercised	500	—
Unsettled repurchases of common stock	12,491	—

B. New Accounting Standards

In June 2011, the FASB issued new guidance to improve the comparability, consistency, and transparency of financial reporting and to increase the prominence of items reported in other comprehensive income. The new guidance requires an entity to present the total of comprehensive income either in a single continuous statement of comprehensive income or in two separate but consecutive statements. In both presentations, an entity is required to present on the face of the financial statements reclassification adjustments for items that are reclassified from other comprehensive income to net income in the statement(s) where the components of net income and the components of other comprehensive income are presented. Historically, the Company has used the consecutive two-statement approach; however, this new guidance will require additional disclosure on the Company's statement of operations and related notes. The new guidance is required to be applied retrospectively and is effective for fiscal years, and interim periods within those years, beginning after December 15, 2011.

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 was adopted during the first quarter of 2011. During the three, nine and twelve months ended September 30, 2011, the Company had no purchases, sales, issuances or settlements in the Level 3 category. This guidance requires additional disclosure on fair value measurements but did not impact the Company's consolidated financial statements.

C. 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

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 called for an annual non-fuel base rate increase of $17.15 million effective for usage beginning July 1, 2010. The new rate structure resulted in net increases in base rates during the peak summer season of May through October and net decreases in base rates during November through April. 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. 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 10-year amortization. The settlement provided 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, discussed below) 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.

El Paso City Council Actions. On October 4, 2011, the El Paso City Council (the “City”) adopted a resolution ordering the Company to show cause why its base rates for electric service within the city limits of El Paso should not be lowered (the “Show Cause Order”) which the Company has appealed as discussed below. Pursuant to the Show Cause Order, the Company would be required to file a rate case with the City no later than February 1, 2012. The City would then have until the 185th day after the date that the Company files its rate case to make a determination regarding the Company's base rates in El Paso. If the Company is ultimately required to file a rate case with the City for rates inside the city limits, the Company plans to simultaneously file a rate case with the other cities in its Texas service area and with the PUCT for rates outside any city limits.

The City conducted a hearing on temporary rates on October 25, 2011, and has scheduled an additional hearing for November 15, 2011. The revenues collected under temporary rates, if any, are subject to true-up to higher final rates approved by the PUCT and could be subject to refund if final rates are lower than temporary rates and a refund is authorized by the PUCT. The ultimate authority to set the Company's Texas electric rates is vested in the PUCT.

On October 27, 2011, the Company filed an appeal with the PUCT to set aside the City's Show Cause Order or in the alternative issue an order staying the City's Show Cause Order and corresponding jurisdictional deadlines until the City can establish that it has complied with Texas statutes. The Company intends to vigorously defend its rates, which were lawfully approved only last year by the City and the PUCT as just and reasonable. If the City succeeds in implementing lower rates, the resulting lower rates would have a negative impact on the Company's revenues, net income, and cash from operations.The Company cannot predict the outcome of this matter and the Company is unable to predict the effect, if any, this would have on the Company's future operations, cash flows, and financial condition.

Fuel Reconciliation Case (Severed from 2009 Rate Case). Pursuant to the stipulation in Docket No. 37690, a 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 (the “ALJ”) 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.

The Company has filed the following petitions with the PUCT to refund recent fuel cost over-recoveries, due primarily to fluctuations in natural gas markets and consumption levels. The table summarizes the docket number assigned by the PUCT, the dates the Company filed the petitions and the dates a final order was issued by the PUCT approving the refunds to customers. The fuel cost over-recovery periods represent the months in which the over-recoveries took place and the refund periods represent the

Table of Contents
EL PASO ELECTRIC COMPANY AND SUBSIDIARY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

billing month(s) in which customers received the refund amounts shown, including interest (in thousands):

Docket No.	Date Filed	Date Approved	Recovery Period	Refund Period	Refund Amount
37788	December 17, 2009	February 11, 2010	September – November 2009	February 2010	$11,800
38253	May 12, 2010	July 15, 2010	December 2009 – March 2010	July – August 2010	11,100
38802	October 20, 2010	December 16, 2010	April – September 2010	December 2010	12,800
39159	February 18, 2011	May 3, 2011	October – December 2010	April 2011	11,800

The Company has filed the following petitions with the PUCT to revise its fixed fuel factor pursuant to the fuel factor formula authorized in PUCT Docket No. 37690:

Docket No.	Date Filed	Date Approved	Increase(Decrease) in Fuel Factor	Effective Billing Month
38895	November 23, 2010	January 6, 2011	(14.7)%	January 2011
39599	July 15, 2011	August 30, 2011	9.4%	August 2011

Application for Approval to Revise Energy Efficiency Cost Recovery Factor for 2012. On May 2, 2011, 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. 39376. A unanimous settlement resolving all issues was filed with the PUCT on July 15, 2011. The settlement allows the Company to recover $8.3 million and supports the Company's request to revise its demand and energy goals and EECRF cost caps as well as the Company's request to increase its 2012 EECRF, effective beginning with the first billing cycle of its January 2012 billing month. A final order in the case was issued August 23, 2011, approving the settlement.

Petition for Approval to Revise Military Base Discount Recovery Factor. On July 14, 2011, the Company filed with the PUCT a petition requesting approval to revise its Military Base Discount Recovery Factor ("MBDRF") tariff to account for under-recovery of discount charges during 2010 and for 2011 discounts. The total requested in the filing is $4.3 million and the case was assigned Docket No. 39590. A hearing in this case is scheduled for November 9, 2011.

Application for a Certificate of Convenience and Necessity ("CCN") for Rio Grande Unit 9. On September 30, 2010, the Company filed a petition seeking a CCN 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. A unanimous settlement to approve the CCN was filed on March 2, 2011, and a final order granting the CCN was approved on April 8, 2011.

Project to Investigate Early February 2011 Outages and Curtailments. On February 8, 2011, the PUCT opened Project No. 39134, Investigation into Power Outages in El Paso Electric's Service Territory. In this project, the PUCT is investigating the Company's power plant outages and customer curtailments that occurred February 2-4, 2011, as a result of the extreme cold weather in the El Paso area. There was no accompanying PUCT order for the opening of this project. The PUCT Staff conducted discovery in the investigation. On February 14, 2011, the Company also filed a report on this weather event. On May 13, 2011, the PUCT Staff issued a report stating that, as of then, it had not identified violations by the Company of the Texas electric utility regulatory statute or PUCT rules. The report also stated that the PUCT Staff would continue to monitor the extreme cold weather event results and subsequent forthcoming information as the Company and other regulatory agencies complete their ongoing investigations.

On February 15, 2011, the City Council of El Paso adopted a motion that, upon completion of hearings and investigations concerning the extreme cold weather event, requires the Mayor to call for Special City Council meetings or public hearings, on utility issues related to the weather event.

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 new rate structure resulted in net increases in base rates during the peak summer season of May through October and net decreases in base rates during November through April. 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.

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. On March 18, 2011, the Company entered into an uncontested stipulation which would provide for a rate per kWh of energy efficiency savings that would be recovered through the efficient use of energy rider. A hearing on the uncontested stipulation was held on April 26, 2011 and briefs were filed on September 26, 2011.

Application for a CCN for Rio Grande Unit 9. On September 30, 2010, the Company filed a petition seeking a CCN 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. On March 4, 2011, NMPRC Staff filed testimony in support of the Company's application and no party filed testimony or a position statement opposing the application. On April 13, 2011 an unopposed stipulation was filed in this case seeking approval of a CCN for the Company to construct, own and operate the 87 MW generating unit. A final order on this case approving the CCN was issued on June 23, 2011.

Application for Approval of 2011 New and Modified Energy Efficiency Programs. On February 15, 2011, the Company filed its Application for Approval of New and Modified Energy Efficiency Programs for 2011 with the NMPRC. On June 22, 2011, parties to this case entered into a partial stipulation, agreeing on all issues, except for a military base free-ridership issue. On June 24, 2011, the New Mexico Attorney General filed a statement in opposition to the proposed partial stipulation. On July 8, 2011, the Company filed its testimony in support of the partial stipulation. A hearing in this case was held on July 27-28, 2011.

2011 Renewable Procurement Plan Pursuant to the Renewable Energy Act. On July 1, 2011, the Company filed its Application for Approval of its 2011 Renewable Procurement Plan with the NMPRC, which was assigned NMPRC Case No. 11-00263-UT. The filing identified renewable resources intended to meet the Company's Renewable Portfolio Standard ("RPS") requirements in 2012 and 2013. The renewable resources in the 2011 Renewable Procurement Plan which were previously approved by the NMPRC will allow the Company to meet the full RPS requirement of 10% of the Company's jurisdictional retail energy sales for 2012 and 2013. The Company's 2011 Plan also addresses the diversity targets in 2012 and 2013 required by NMPRC Rule 572 and demonstrates that the Company will meet those targets. The plan also demonstrates that the Company will meet its solar diversity target in 2012 and comply with the terms of a previously-approved variance for 2011. A hearing in this case was held on October 13, 2011.

Investigation into Rates for Church Customers. On July 12, 2011, the NMPRC initiated an investigation into the rates the Company charges its church customers which were approved in Case No. 09-00171-UT. The investigation, Case No. 11-00276-UT, was ordered to determine whether the Company's rates to its church customers are unjust and unreasonable and should be revised. The Company filed a response on August 1, 2011. A mediation conference was held on August 23, 2011 which resulted in an Unopposed Joint Stipulation, filed on October 14, 2011. The stipulation limits billing impacts to religious organizations that take service under the Company's standard small commercial rate. The stipulation was approved by the NMPRC on October 27, 2011.

Revolving Credit Facility and Guarantee of Debt. On October 13, 2011, the Company received final approval from the NMPRC in Case No. 11-00349-UT to amend and restate the Company's $200 million revolving credit facility ("RCF"), which includes an option, subject to lender's approval, to expand the size to $300 million, and to incrementally issue up to $300 million of long-term debt as and when needed.

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 (the “Court of Appeals”) 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.

On August 31, 2011, the FERC issued an order approving a settlement between TEP and the Company which became effective November 1, 2011. The settlement reduces TEP’s transmission rights under the Transmission Agreement from 200 MW to 170 MW and TEP and the Company have entered into two new firm transmission capacity agreements at applicable tariff rates for a total of 40 MW. Under the terms of the settlement, the Company recorded approximately $5.4 million in transmission revenues for the period February 1, 2006 through September 30, 2011, including interest income. This adjustment was recorded in the three months ended September 30, 2011. The Company shared with its customers 25% of the transmission revenues earned before July 1, 2010, or approximately $0.7 million, through a credit to Texas fuel recoveries. The Company estimates that the settlement will also add approximately $0.2 million to its transmission revenues for the remainder of 2011. The Company will withdraw its appeal before the Court of Appeals.

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. TEP has informed the Company that it is in the process of having the lawsuit dismissed.

Inquiry into Early February 2011 Outages and Curtailments. On February 14, 2011, the FERC directed its staff to initiate an inquiry into power plant outages and customer curtailments by power generators and gas suppliers in the Southwestern United States, including the Company, in early February 2011, as a result of the extreme cold weather. The FERC specifically stated that its inquiry is not an enforcement investigation. On August 16, 2011, the FERC released its staff report, Docket No. AD11-9-000, making recommendations to help prevent a recurrence of such outages in the future.

Revolving Credit Facility and Guarantee of Debt. On October 13, 2011, the Company received final approval from the FERC in Docket No. ES11-43-000 to amend and restate the Company's $200 million RCF, which includes an option, subject to lender's approval, to expand the size to $300 million, and to incrementally issue up to $300 million of long-term debt as and when needed.

D. Palo Verde

License Extension. On April 21, 2011, the Company, along with the other Palo Verde Participants, was notified that the NRC had renewed the operating licenses for all three units at Palo Verde. The renewed licenses for Units 1, 2 and 3 will now expire in 2045, 2046 and 2047, respectively. For the second and third quarters of 2011 combined, the extension of the operating licenses had the effect of reducing depreciation and amortization expense by approximately $5.3 million and reducing the accretion expense on the Palo Verde asset retirement obligation by approximately $2.0 million.

Decommissioning. Decommissioning costs are estimated every three years based upon engineering cost studies performed by outside engineers retained by APS. On March 30, 2011, the Palo Verde Participants approved the 2010 Palo Verde decommissioning study (the “2010 Study”). The 2010 Study reflects the increase in the license life from 40 years to 60 years. The 2010 Study estimated that the Company must fund approximately $357.4 million (stated in 2010 dollars) to cover its share of decommissioning costs which was an increase in decommissioning costs from the 2007 Palo Verde decommissioning study (the “2007 Study”). The net effect of these changes will result in lower asset retirement obligations and lower expenses in the future. See Note E for additional discussion. Although the 2010 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.

Oversight of the Nuclear Energy Industry in the Wake of the Earthquake and Tsunami in Japan. On March 11, 2011, a 9.0 magnitude earthquake occurred off the northeastern coast of Japan. The earthquake produced a tsunami that caused significant damage to the Fukushima Daiichi Nuclear Power Station in Japan. Preliminary data available from the Fukushima Daiichi plant operator and Japanese government have each indicated that the earthquake and tsunami were beyond the plant’s required licensing and design parameters. Validation of that data will continue as more information becomes available.

The Nuclear Energy Institute (“NEI”) and the Institute of Nuclear Power Operations (“INPO”) are working closely to analyze the situation in Japan and develop action plans for U.S. nuclear power plants. APS, which operates Palo Verde Nuclear Generating Station, is actively engaged with NEI and INPO in these efforts. Additionally, the NRC is performing its own independent review of the events at Fukishima Daiichi. On March 23, 2011, the NRC Commissioners voted to launch a review of U.S. nuclear power plant safety. The NRC established an agency task force (the "Task Force") to conduct both near and long-term analyses of the lessons learned from the Fukishima Daiichi nuclear accident in Japan. The report of the Task Force was released on July 12, 2011. The Task Force conducted a systematic and methodical review of NRC processes and regulations to make policy recommendations in light of the accident at Fukishima Daiichi Nuclear Power Plant. The Task Force made certain recommendations and concluded that a sequence of events like the Fukishima accident is unlikely to occur in the United States and some appropriate mitigation measures have been implemented reducing the likelihood of core damage and radiological releases. The Task Force further concluded that continued licensing activities do not pose an imminent risk to public health and safety.

E. Accounting for Asset Retirement Obligations

The Company complies with FASB guidance for asset retirement obligations ("ARO"). FASB guidance requires the Company to revise its previously recorded ARO for any changes in estimated cash flows including changes in estimated probabilities related to timing of settlements. In April 2011, the Company implemented the recently approved 2010 Palo Verde decommissioning study, and as a result, revised its ARO related to Palo Verde to (i) increase estimated cash flows from the 2007 Study to the 2010 Study, and (ii) change estimated probabilities due to Palo Verde license extension (see Note D). The assumptions used to calculate the original ARO liability and the revised ARO liability are as follows:

	Escalation Rate	Credit-Risk Adjusted Discount Rate
Original ARO liability	3.60%	9.50%
Incremental ARO liability	3.60%	6.20%

EL PASO ELECTRIC COMPANY AND SUBSIDIARY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

A roll forward of the Company's ARO liability is presented below and revisions to estimates include both the increase to estimated cash flows and the change in estimated probabilities due to Palo Verde license extension.

	2011	2010
	(in thousands)	
ARO liability at beginning of year	$92,911	$85,358
Revisions to estimates	(41,670)	—
Accretion expense	4,499	5,942
Liabilities settled	(796)	(357)
ARO liability at September 30	$54,944	$90,943

F. Common Stock

Repurchase Program. Details regarding the Company's stock repurchase program are presented below:

	Since 1999 (a)	Three Months Ended September 30,	Nine Months Ended September 30,	Authorized Shares
Shares repurchased	25,125,795	1,591,317	2,502,066	
Cost, including commission (in thousands) (b)	$414,413	$50,954	$77,274	
2010 Plan balance at December 31, 2010				676,271
2011 Plan repurchase shares authorized (c)				2,500,000
Total remaining shares available for repurchase at September 30, 2011				674,205

(a) Represents repurchased shares and cost since inception of the stock repurchase program in 1999.

(b) Costs of repurchased shares for the three and nine months ended September 30, 2011 include $12.5 million related to transactions that were not settled as of September 30, 2011.

(c) On March 21, 2011, the Board of Directors authorized an additional repurchase of the Company's common stock (the "2011 Plan").

The Company may in the future make purchases of its common stock pursuant to its authorized programs 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.

Dividend Policy. On September 30, 2011, the Company paid $9.2 million of quarterly dividends to shareholders. The Company has paid a total of $18.4 million in cash dividends during the nine months ended September 30, 2011.

Basic and Diluted Earnings Per Share. The basic and diluted earnings per share are presented below (in thousands except for share data):

	Three Months Ended September 30,	
	2011	2010
Weighted average number of common shares outstanding:		
Basic number of common shares outstanding	41,307,632	42,921,044
Dilutive effect of unvested performance awards	231,230	117,796

Dilutive effect of stock options	26,111	64,858
Diluted number of common shares outstanding	41,564,973	43,103,698
Basic net income per common share:		
Net income	$58,321	$60,182
Income allocated to participating restricted stock	(275)	(260)
Net income available to common shareholders	$58,046	$59,922
Diluted net income per common share:		
Net income	$58,321	$60,182
Income reallocated to participating restricted stock	(273)	(259)
Net income available to common shareholders	$58,048	$59,923
Basic net income per common share:		
Distributed earnings	$0.22	$—
Undistributed earnings	1.19	1.40
Basic net income per common share	$1.41	$1.40
Diluted net income per common share:		
Distributed earnings	$0.22	$—
Undistributed earnings	1.18	1.39
Diluted net income per common share	$1.40	$1.39

	Nine Months Ended September 30,	
	2011	2010
Weighted average number of common shares outstanding:		
Basic number of common shares outstanding	41,819,428	43,370,487
Dilutive effect of unvested performance awards	198,578	76,960
Dilutive effect of stock options	33,301	57,987
Diluted number of common shares outstanding	42,051,307	43,505,434
Basic net income per common share:		
Net income	$98,086	$93,138
Income allocated to participating restricted stock	(447)	(383)
Net income available to common shareholders	$97,639	$92,755
Diluted net income per common share:		
Net income	$98,086	$93,138
Income reallocated to participating restricted stock	(445)	(382)
Net income available to common shareholders	$97,641	$92,756
Basic net income per common share:		
Distributed earnings	$0.44	$—
Undistributed earnings	1.89	2.14
Basic net income per common share	$2.33	$2.14
Diluted net income per common share:		
Distributed earnings	$0.44	$—
Undistributed earnings	1.88	2.13
Diluted net income per common share	$2.32	$2.13

	Twelve Months Ended September 30,	
	2011	2010
Weighted average number of common shares outstanding:		
Basic number of common shares outstanding	41,969,628	43,523,270
Dilutive effect of unvested performance awards	192,994	85,595
Dilutive effect of stock options	44,390	63,459

Diluted number of common shares outstanding	42,207,012	43,672,324
Basic net income per common share:		
Net income	$105,551	$101,099
Income allocated to participating restricted stock	(461)	(405)
Net income available to common shareholders	$105,090	$100,694
Diluted net income per common share:		
Net income	$105,551	$101,099
Income reallocated to participating restricted stock	(459)	(404)
Net income available to common shareholders	$105,092	$100,695
Basic net income per common share:		
Distributed earnings	$0.44	$—
Undistributed earnings	2.06	2.31
Basic net income per common share	$2.50	$2.31
Diluted net income per common share:		
Distributed earnings	$0.44	$—
Undistributed earnings	2.05	2.31
Diluted net income per common share	$2.49	$2.31

Table of Contents
EL PASO ELECTRIC COMPANY AND SUBSIDIARY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

The amount of restricted stock awards, performance shares and stock options excluded from the calculation of the diluted number of common shares outstanding because their effect was antidilutive is presented below:

	Three Months Ended September 30,		Nine Months Ended September 30,		Twelve Months Ended September 30,	
	2011	2010	2011	2010	2011	2010
Restricted stock awards	90,358	77,959	84,691	74,263	83,091	72,798
Performance shares (a)	—	—	—	32,300	—	24,225
Stock options	—	—	—	—	—	—

(a) Performance shares excluded from the computation of diluted earnings per share assume a 100% performance level payout,
as no payouts would be required based upon performance at the end of each corresponding period.

G. Income Taxes

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. The Company is currently under audit in the federal jurisdiction for 2009 and in Texas for 2007. 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.

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 non-cash charge to income tax expense of approximately $4.8 million in the first quarter of 2010.

The Company's consolidated effective tax rates on income before extraordinary item are presented in the tables below:

	Effective Tax Rates					
	Three Months Ended September 30,		Nine Months Ended September 30,		Twelve Months Ended September 30,	
	2011	2010	2011	2010	2011	2010
Federal statutory tax rate	35.0 %	35.0 %	35.0 %	35.0 %	35.0 %	35.0 %
Consolidated effective tax rate	36.6 %	35.3 %	34.8 %	38.0 %	33.3 %	36.6 %
Without PPACA	36.6 %	35.3 %	34.8 %	34.6 %	33.3 %	33.5 %

The Company's consolidated effective tax rate for the three, nine and twelve months ended September 30, 2011 and the three months ended September 30, 2010, differs from the federal statutory tax rate primarily due to the allowance for equity funds used during construction and state income taxes. The Company's effective tax rates for the nine and twelve months ended September 30, 2010, without the effect of the enactment of the PPACA differ from the federal statutory tax rate primarily due to state income taxes, the allowance for equity funds used during construction, the tax rate on earnings on qualified decommissioning trust investments, and various permanent tax differences.

H. Commitments, Contingencies and Uncertainties

For a full discussion of commitments and contingencies, see Note J of Notes to Consolidated Financial Statements in the 2010 Form 10-K. In addition, see Note C above and Notes B and D of Notes to Consolidated Financial Statements in the 2010 Form 10-K regarding matters related to wholesale power sales contracts and transmission contracts subject to regulation and Palo Verde, including decommissioning, spent fuel storage, disposal of low-level radioactive waste, and liability and insurance matters.

Power Purchase and Sale Contracts

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. For a full discussion of power purchase and sale contracts that the Company has entered into with various counterparties, see Note J of Notes to Consolidated Financial Statements in the 2010 Form 10-K. In addition to the contracts disclosed in the 2010 Form 10-K, in April 2011, the amount of energy purchased from Freeport-McMoran Copper and Gold Energy Services LLC was increased to 125 MW through December 2013, in accordance with the power purchase and sale agreement. In the third quarter of 2011, the purchase power agreement for the full capacity of two 12 MW solar photovoltaic plants to be built in southern New Mexico was modified to the full capacity of one 12 MW solar photovoltaic plant and one 10 MW solar photovoltaic plant scheduled for commercial operation in March 2012 and April 2012, respectively.

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 ("SO_2"), 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. The U.S. Court of Appeals for the District of Columbia voided CAIR in 2008; however, the Company has complied with CAIR since 2009. The annual reconciliation to comply with CAIR is due by March 31 of the following year. The Company has purchased allowances and expensed the following costs to meet its annual requirements:

Compliance Year	Amount (in thousands)
2010	$370
2011	35

Clean Air Transport Rule/Cross-State Air Pollution Rule. On July 6, 2011, the EPA finalized the Clean Air Transport Rule ("CATR"), renaming it the Cross-State Air Pollution Rule ("CSAPR"). The rule replaces CAIR and addresses air quality issues in downwind states, specifically eastern, central and southern parts of the United States. CSAPR will require 27 states, including Texas, to issue regulations and develop a scheme by which power plants in their respective jurisdictions will further reduce SO2 and NOx. The CSAPR does not apply to the Company's facilities in New Mexico. The rule becomes effective on January 1, 2012, but it is unclear when and how the states would issue implementing regulations. The Company continues to evaluate the rule, including recently proposed revisions, to determine potential impacts. Due to various uncertainties, 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 was in the process of revising these standards; however, on September 2, 2011, EPA withdrew its draft proposal, indicating it does not plan to revisit this issue until 2013. If these future 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. The impact of these regulations and associated costs, however, 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 by Congress in the future. The EPA has also proposed using the CAA to limit carbon dioxide and other GHG emissions.

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, and the first report containing 2010 emissions was submitted to the EPA prior to the September 30, 2011 due date. The Company also has inventoried and implemented procedures for electrical equipment containing sodium hexafluoride ("SF_6"), another GHG. The Company is tracking these GHG emissions pursuant to the EPA's new SF_6 reporting rule that was finalized in late 2010 and became effective January 1, 2011.

The 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 100,000 tons 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, the 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, the EPA was to propose standards for both new and modified boilers and for existing facilities in September 2011, and finalize those standards by May 26, 2012. However, on September 15, 2011, the EPA again postponed a proposed rule and stated a new schedule would be proposed "soon". The impact of these rules on the Company is unknown at this time, but they could result in significant 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 September 30, 2011, 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 during the three, nine and twelve months ended September 30, 2011 and 2010 to comply with federal environmental statutes (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,		Twelve Months Ended September 30,	
	2011	2010	2011	2010	2011	2010
Clean Air Act	$164	$88	$457	$376	$696	$523
Clean Water Act	63	51	172	154	196	305

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 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 an agreement with the EPA and a former property owner to resolve this matter and on June 30, 2011 the Company entered 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 September 30, 2011).
Environmental Litigation and Investigations. 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 the 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. If the agencies certify impairment, the EPA is required to evaluate and, if necessary, determine "best available retrofit technology" ("BART") for Four Corners. On January 19, 2011, a similar group of environmental organizations filed a lawsuit against the Departments of Interior and Agriculture, alleging, among other things, that the agencies failed to act on the February 2010 petition "without unreasonable delay" and requesting the court to order the agencies to act on the petition within 30 days. 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.
On May 7, 2010, APS, on behalf of the Four Corners co-owners (the "Project Participants"), received Notice of Intent to Sue Four Corners Power Plant for Violations of the Clean Air Act (the "Notice"). EarthJustice sent the Notice on behalf of Dine CARE (Citizens Against Ruining our Environment), to Nizhoni Ani, National Parks Conservation Association, and the Sierra Club. The Notice alleges two Clean Air Act violations: (i) Prevention of Significant Deterioration violations, and (ii) New Source Performance Standards violations. The alleged violations concern pulverizer projects on Units 4-5 in the 1980's and boiler, turbine, generator and other projects on Units 4-5

commencing in 2007. The Company recently received word that EarthJustice filed a lawsuit in the United States District Court for New Mexico on October 4, 2011 regarding these alleged Clean Air Act violations. The Company has not yet been served with the lawsuit, and the Company is unable to predict the outcome of these alleged violations.

I. 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 C for discussion of the effects of government legislation and regulation on the Company.

J. Employee Benefits

Retirement Plans

The net periodic benefit cost recognized for the three, nine and twelve months ended September 30, 2011 and 2010 is made up of the components listed below as determined using the projected unit credit actuarial cost method (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,		Twelve Months Ended September 30,	
	2011	2010	2011	2010	2011	2010
Components of net periodic benefit cost:						
Service cost	$1,712	$1,516	$5,137	$4,548	$6,653	$5,932
Interest cost	3,497	3,407	10,491	10,222	13,898	13,518
Amendments	—	—	—	—	838	—
Expected return on plan assets	(3,523)	(3,467)	(10,571)	(10,400)	(14,038)	(14,259)
Amortization of:						
Net loss	1,636	887	4,908	2,661	5,796	3,067
Prior service cost	29	29	87	87	115	115
Net periodic benefit cost	$3,351	$2,372	$10,052	$7,118	$13,262	$8,373

During the nine months ended September 30, 2011, the Company contributed $13.4 million of its projected $13.9 million 2011 annual contribution to its retirement plans.

Other Postretirement Benefits

The net periodic benefit cost recognized for the three, nine and twelve months ended September 30, 2011 and 2011 is made up of the components listed below (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,		Twelve Months Ended September 30,	
	2011	2010	2011	2010	2011	2010
Components of net periodic benefit cost:						
Service cost	$747	$889	$2,241	$2,668	$3,131	$3,516
Interest cost	1,345	1,666	4,034	4,998	5,700	6,621
Expected return on plan assets	(455)	(382)	(1,367)	(1,147)	(1,749)	(1,521)
Amortization of:						
Prior service benefit	(1,482)	(717)	(4,445)	(2,152)	(5,162)	(2,869)
Net gain	(11)	(44)	(30)	(131)	(74)	(131)
Net periodic benefit cost	$144	$1,412	$433	$4,236	$1,846	$5,616

During the nine months ended September 30, 2011, the Company contributed $2.2 million to fund its entire annual contribution to its postretirement plan for 2011.

K. 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, short-term borrowings under the RCF, 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 Short-Term Borrowings Under the RCF. The fair values of the Company's long-term debt and short-term borrowings under the RCF are based on estimated market prices for similar issues and are presented below (in thousands):

	September 30, 2011		December 31, 2010	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Pollution Control Bonds	$193,135	$207,552	$193,135	$192,924
Senior Notes	546,649	603,490	546,610	574,700
RGRT Senior Notes (1)	110,000	115,235	110,000	110,371
RCF (1)	17,793	17,793	4,704	4,704
Total	$867,577	$944,070	$854,449	$882,699

(1) Nuclear fuel financing as of September 30, 2011 is funded through the $110.0 million RGRT Senior Notes and $17.8 million under the RCF. The interest rate on the Company's borrowings under the RCF is reset throughout the quarter reflecting current market rates. Consequently, the carrying value approximates 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 $158.4 million and $153.9 million at September 30, 2011 and December 31, 2010, 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):

	September 30, 2011					
	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	$4,431	$(28)	$—	$—	$4,431	$(28)
U.S. Government Bonds	1,938	(28)	—	—	1,938	(28)
Municipal Obligations	7,979	(180)	2,571	(45)	10,550	(225)
Corporate Obligations	4,423	(159)	92	(4)	4,515	(163)
Total Debt Securities	18,771	(395)	2,663	(49)	21,434	(444)
Common Stock	20,284	(3,000)	2,255	(760)	22,539	(3,760)
Total Temporarily Impaired Securities	$39,055	$(3,395)	$4,918	$(809)	$43,973	$(4,204)

(1) Includes approximately 127 securities.

	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 (2):						
Federal Agency Mortgage Backed Securities	$2,290	$(51)	$441	$(27)	$2,731	$(78)
U.S. Government Bonds	9,583	(124)	—	—	9,583	(124)
Municipal Obligations	13,145	(278)	3,763	(145)	16,908	(423)
Corporate Obligations	1,855	(18)	—	—	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)

(2) Includes approximately 96 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 recorded 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 2044 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):

	September 30, 2011		December 31, 2010	
	Fair Value	Unrealized Gains	Fair Value	Unrealized Gains
Description of Securities:				
Federal Agency Mortgage Backed Securities	$24,272	$1,251	$18,472	$793
U.S. Government Bonds	10,437	1,034	10,450	183
Municipal Obligations	24,417	1,427	15,633	592
Corporate Obligations	7,298	475	7,223	362
Total Debt Securities	66,424	4,187	51,778	1,930
Common Stock	43,225	10,419	56,770	14,142
Cash and Cash Equivalents	4,815	—	3,007	—
Total	$114,464	$14,606	$111,555	$16,072

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 of these available-for-sale securities as of September 30, 2011 is as follows (in thousands):

	Total	2011 through 2012	2013 through 2016	2017 through 2021	2022 and Beyond
Municipal Debt Obligations	$34,967	$1,321	$13,035	$13,043	$7,568

Corporate Debt Obligations	11,813	1,378	3,893	3,533	3,009
U.S. Government Bonds	12,375	1,320	1,109	6,428	3,518

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 three, nine and twelve months ended September 30, 2011 and 2010, the Company recognized other than temporary impairment losses on its available-for-sale securities as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,		Twelve Months Ended September 30,	
	2011	2010	2011	2010	2011	2010
Gross unrealized holding losses included in pre-tax income	$(1,547)	$—	$(1,746)	$(263)	$(1,746)	$(408)

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

	Three Months Ended September 30,		Nine Months Ended September 30,		Twelve Months Ended September 30,	
	2011	2010	2011	2010	2011	2010
Proceeds from sales of available-for-sale securities	$31,435	$12,731	$67,841	$46,936	$82,561	$74,799
Gross realized gains included in pre-tax income	$552	$95	$1,248	$621	$1,657	$3,981
Gross realized losses included in pre-tax income	(289)	(288)	(583)	(960)	(512)	(1,327)
Gross unrealized losses included in pre-tax income	(1,547)	—	(1,746)	(263)	(1,746)	(408)
Net gains (losses) in pre-tax income	$(1,284)	$(193)	$(1,081)	$(602)	$(601)	$2,246
Net unrealized holding gains (losses) included in accumulated other comprehensive income	$(7,503)	$7,019	$(4,914)	$3,041	$(1,290)	$4,619
Net gains (losses) reclassified out of accumulated other comprehensive income	1,284	193	1,081	602	601	(2,246)
Net gains (losses) in other comprehensive income	$(6,219)	$7,212	$(3,833)	$3,643	$(689)	$2,373

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 which are included in deferred charges and other assets on the consolidated balance sheets. 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. 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.

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 September 30, 2011 and December 31, 2010, 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 September 30, 2011	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	$2,776	$—	$—	$2,776
Available for sale:				
U.S. Government Bonds	$12,375	$12,375	$—	$—
Federal Agency Mortgage Backed Securities	28,703	—	28,703	—
Municipal Bonds	34,967	—	34,967	—
Corporate Asset Backed Obligations	11,813	—	11,813	—
Subtotal Debt Securities	87,858	12,375	75,483	—
Common Stock	65,764	65,764	—	—
Cash and Cash Equivalents	4,815	4,815	—	—
Total available for sale	$158,437	$82,954	$75,483	$—

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	$—	$—	$2,909
Available for sale:				
U.S. Government Bonds	$20,033	$20,033	$—	$—
Federal Agency Mortgage Backed Securities	21,204	—	21,204	—
Municipal Bonds	32,541	—	32,541	—
Corporate Asset Backed Obligations	9,077	—	9,077	—
Subtotal Debt Securities	82,855	20,033	62,822	—
Common Stock	68,016	68,016	—	—
Cash and Cash Equivalents	3,007	3,007	—	—
Total available for sale	$153,878	$91,056	$62,822	$—

There were no transfers in and out of Level 1 and Level 2 fair value measurements categories during the three, nine and twelve month periods ending September 30, 2011 and September 30, 2010. There were no purchases, sales, issuances, and settlements related to the assets in the Level 3 fair value measurement category during the three, nine and twelve month periods ending September 30, 2011 and 2010.

Table of Contents

Report of Independent Registered Public Accounting Firm
The Board of Directors and Shareholders
El Paso Electric Company:

We have reviewed the consolidated balance sheet of El Paso Electric Company and subsidiary as of September 30, 2011, the related consolidated statements of operations and comprehensive operations for the three-month, nine-month and twelve-month periods ended September 30, 2011 and 2010, and the related consolidated statements of cash flows for the nine-month periods ended September 30, 2011 and 2010. These consolidated financial statements are the responsibility of the Company's management.

We conducted our reviews in accordance with the standards of the Public Company Accounting Oversight Board (United States). A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with the standards of the Public Company Accounting Oversight Board (United States), the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

Based on our reviews, we are not aware of any material modifications that should be made to the consolidated financial statements referred to above for them to be in conformity with U.S. generally accepted accounting principles.

We have previously audited, in accordance with standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet of El Paso Electric Company and subsidiary as of December 31, 2010, and the related consolidated statements of operations, comprehensive operations, changes in common stock equity, and cash flows for the year then ended (not presented herein); and in our report dated February 25, 2011, we expressed an unqualified opinion on those consolidated financial statements. In our opinion, the information set forth in the accompanying consolidated balance sheet as of December 31, 2010, is fairly stated, in all material respects, in relation to the consolidated balance sheet from which it has been derived.

/s/ KPMG LLP
Houston, Texas
November 4, 2011

Table of Contents

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

The information contained in this Item 2 updates, and should be read in conjunction with, the information set forth in Part II, Item 7 of our 2010 Form 10-K.

FORWARD-LOOKING STATEMENTS

Certain matters discussed in this Quarterly Report on Form 10-Q 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 including, 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 rates in El Paso following the potential rate case associated with the El Paso City Council's October 4, 2011 resolution ordering us to show cause why our base rates for El Paso customers should not be lowered and the potential implementation of temporary rates by the El Paso City Council,
- 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, including costs to comply with any potential new or expanded regulatory requirements,
- 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,

Table of Contents

- the impact of recent 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 the 2010 Form 10-K under the headings “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.

Summary of Critical Accounting Policies and Estimates

The preparation of our financial statements requires management to make estimates and assumptions that affect the amounts reported in the consolidated financial statements and related notes for the periods presented and actual results could differ in future periods from those estimates. Critical accounting policies and estimates are both important to the portrayal of our financial condition and results of operations and require complex, subjective judgments and are more fully described in the “Management’s Discussion and Analysis of Financial Condition and Results of Operations” in our 2010 Form 10-K.

Summary

The following is an overview of our results of operations for the three, nine and twelve month periods ended September 30, 2011 and 2010. Income before extraordinary item for the three, nine and twelve month periods ended September 30, 2011 and 2010 is shown below:

	Three Months Ended September 30,		Nine Months Ended September 30,		Twelve Months Ended September 30,	
	2011	2010	2011	2010	2011	2010
Net income before extraordinary item (in thousands)	$58,321	$49,896	$98,086	$82,852	$105,551	$90,813
Basic earnings per share before extraordinary item	1.41	1.16	2.33	1.90	2.50	2.07

The following table and accompanying explanations show the primary factors affecting the after-tax change in income before extraordinary item between the 2011 and 2010 periods presented (in thousands):

	Three Months Ended	Nine Months Ended	Twelve Months Ended
September 30, 2010 income before extraordinary item	$49,896	$82,852	$90,813
Change in (net of tax):			
Increased retail non-fuel base revenues (a)	8,547	19,862	23,165
Increased transmission revenues (b)	2,161	2,974	3,708
Decreased (increased) outside services expense (c)	309	(1,367)	(1,751)
Increased (decreased) allowance for funds used during construction (d)	(1,486)	(1,717)	4
Increased transmission and distribution operating and maintenance expense (e)	(879)	(1,702)	(2,117)
Increased taxes other than income taxes (f)	(317)	(1,319)	(2,627)

Decreased deregulated Palo Verde Unit 3 revenues (g)	(64)	(1,006)	(1,718)
Decreased off-system sales margins retained (h)	(41)	(3,836)	(5,304)
Elimination of Medicare Part D tax benefit (i)	—	4,787	4,787
Other	195	(1,442)	(3,409)
September 30, 2011 income before extraordinary item	$58,321	$98,086	$105,551

10

Table of Contents

(a) Non-fuel retail base revenues increased for the three, nine, and twelve months ended September 30, 2011 when compared to the same periods in 2010 as the result of increased kWh sales reflecting increased customer growth, favorable weather conditions, increased non-fuel base rates, and the seasonality of our rate structure. For a complete discussion of non-fuel rate base revenues, see page 30.

(b) Transmission revenues increased for all three periods ended September 30, 2011 compared to the same periods last year due to a settlement agreement with Tucson Electric Power Company involving a transmission dispute that resulted in a one-time adjustment to income of $4.5 million, $4.1 million, and $3.9 million, respectively.

(c) Outside services expense increased in the nine and twelve months ended September 30, 2011 compared to the same periods last year due to regulatory activities and additional outside services related to software systems support and improvements.

(d) Allowance for funds used during construction (the "AFUDC") decreased in the three and nine months ended September 30, 2011 compared to the same periods last year primarily due to lower balances of construction work in progress subject to AFUDC.

(e) Transmission and distribution operating and maintenance expense increased in all three periods ended September 30, 2011 compared to the same periods last year primarily due to increased wheeling costs and expenses incurred to comply with specific NERC Critical Infrastructure Protection recommendations.

(f) Taxes other than income taxes increased for all three periods ended September 30, 2011 due to increased revenue-related taxes in Texas. Taxes other than income taxes also increased for the nine and twelve months ended September 30, 2011 compared to the same periods last year due to increased estimated property taxes.

(g) Revenues from retail sales of deregulated Palo Verde Unit 3 decreased for all three periods ended September 30, 2011 compared to the same periods last year due to the increased costs of nuclear fuel and decreased generation at Palo Verde Unit 3.

(h) Off-system sales margins retained decreased in all three periods ended September 30, 2011 compared to the same periods last year due to lower average market prices for power and increased sharing of off-system sales margins with customers from 25% to 90% effective July 2010. Off-system sales margins were negatively impacted by power purchases required for system reliability during extremely cold weather in February 2011 and when wildfires in June 2011 threatened key transmission lines in eastern Arizona and western New Mexico. We reserved for the cost of this power pending a request for recovery.

(i) Income tax expense was incurred in March 2010 to recognize a change in the tax law enacted in the Patient Protection and Affordable Care Act to eliminate the tax benefit related to the Medicare Part D subsidies with no comparable tax expense in the 2011 periods.

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 our 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 such fuel costs.

Table of Contents

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

	Three Months Ended September 30,				Nine Months Ended September 30,				Twelve Months Ended September 30,			
	2011		2010		2011		2010		2011		2010	
Residential	43	%	42	%	41	%	41	%	41	%	40	%
Commercial and industrial, small	34		35		34		35		34		36	
Commercial and industrial, large	7		7		8		8		8		8	
Sales to public authorities	16		16		17		16		17		16	
Total retail non-fuel base revenues	100	%	100	%	100	%	100	%	100	%	100	%

No retail customer accounted for more than 3% of our base revenues during such periods. As shown in the table above, residential and small commercial customers comprise 75% or more of our revenues. While this customer base is more stable, it is also more sensitive to changes in weather conditions. The current 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.

Weather significantly impacts our residential, small commercial and industrial customers, and to a lesser extent, our sales to public authorities. For the three, nine, and twelve months ended September 30, 2011, retail non-fuel base revenues were positively impacted by hotter summer weather when compared to the same periods in 2010. 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 30-year average.

	Three Months Ended September 30,		30-Year	Nine Months Ended September 30,		30-Year	Twelve Months Ended September 30,		30-Year
	2011	2010	Average	2011	2010	Average	2011	2010	Average*
Heating degree days	—	—	3	1,305	1,478	1,376	2,100	2,508	2,420
Cooling degree days	1,787	1,603	1,406	2,997	2,607	2,317	3,128	2,724	2,384

* Calendar year basis.

Customer growth is a key driver of the growth of retail sales. The average number of retail customers grew 1.7% for the three months ended September 30, 2011 and 1.5% for both the nine and twelve months ended September 30, 2011 when compared to the same periods last year. See the tables presented on pages 32, 33 and 34 which provide detail on the average number of retail customers and the related revenues and kWh sales.

Retail non-fuel base revenues. Our rate structure in New Mexico, effective January 1, 2010, and in Texas, effective July 1, 2010, results in net increases in base rates during the peak summer season of May through October and net decreases in base rates during November through April. This will cause our revenues to be more seasonal than in the past.

Retail non-fuel base revenues increased by $13.6 million or 7.6% for the three months ended September 30, 2011 when compared to the same period last year primarily due to a 3.9% increase in kWh sales to retail customers reflecting hotter summer weather and 1.7% growth in the average number of customers served. During the three months ended September 30, 2011, cooling degree days were over 11% above the same period in 2010 and 27% above the 30-year average. KWh sales to residential customers and small commercial and industrial customers increased 9.8% and 3.9%, respectively, in the third quarter. Sales to other public authorities increased due to increased sales to military bases at higher non-fuel base rates.

For the nine months ended September 30, 2011, retail non-fuel base revenues increased by $31.5 million or 7.5% compared to the same period in 2010 primarily due to a 3.2% increase in kWh sales to retail customers, reflecting hotter summer weather, and 1.5% growth in the average number of customers served. During the nine months ended

September 30, 2011, cooling degree days were 15% above the same period in 2010 and 29% above the 30-year average. KWh sales to residential customers and small commercial and industrial customers increased 6.1% and 3.1%, respectively, during the nine months ended September 30, 2011 compared to the same period last year. The increase in retail non-fuel base revenues is also due to the seasonal non-fuel base rates which became effective July 1, 2010 in Texas which are higher in the summer months of May to October and lower in the winter months of November to April. Sales to other public authorities increased due to increased sales to military bases at higher non-

Table of Contents

fuel base rates.

Retail non-fuel base revenues for the twelve months ended September 30, 2011 increased by $36.8 million or 6.9% compared to the same period in 2010 primarily due to (i) higher rates in Texas effective July 1, 2010 and in New Mexico effective January 1, 2010, and (ii) a 3.0% increase in kWh sales to retail customers reflecting hotter summer weather and 1.5% growth in the average number of customers served. During the twelve months ended September 30, 2011, cooling degree days were 15% above the same period in 2010 and 31% above the 30-year average. KWh sales to residential customers and small commercial and industrial customers increased 5.9% and 2.7% during the twelve months ended September 30, 2011 compared to the same period last year. Sales to other public authorities increased due to increased sales to military bases at higher non-fuel base rates.

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. We can seek to revise our fixed fuel factor based upon an 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. Fuel over and under recoveries are considered material when they exceed 4% of the previous twelve months' fuel costs.

In the three and nine months ended September 30, 2011, we under-recovered our fuel costs by $3.8 million and $17.5 million, respectively, compared to a fuel over-recovery of $9.7 million and $21.8 million in the same periods in 2010. In January 2011, we implemented a reduced fixed fuel factor in Texas, and in April 2011, we refunded $12.0 million of fuel over-recoveries for the period October 2010 through December 2010 to our Texas customers. In the nine months ended September 30, 2010, we refunded $23.3 million of fuel over-recoveries to our Texas customers. Over-recoveries or under-recoveries in New Mexico and from our FERC customer are refunded through fuel adjustment clauses with a two-month lag.

In the twelve months ended September 30, 2011, we under-recovered our fuel costs by $3.9 million compared to fuel over-recoveries of $28.7 million in the same period last year. Refunds of $23.5 million and $28.5 million were returned to our Texas customers in the twelve months ended September 30, 2011 and 2010, respectively. At September 30, 2011, we had a net fuel under-recovery balance of $10.6 million, including $12.2 million in Texas partially offset by an over-recovery balance of $1.6 million in New Mexico. At September 30, 2010, we had a net fuel over-recovery balance of $16.7 million, including $12.6 million in Texas and $4.1 million in New Mexico.

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 Company shared 25% of off-system sales margins with 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 customers and retain 10% of off-system sales margins.

Off-system sales margins were negatively impacted by power purchases required for system reliability during extremely cold weather in February 2011 and when wildfires in June 2011 threatened key transmission lines in eastern Arizona and western New Mexico. The Company reserved for the cost of this power pending a request for recovery. Retained margins from off-system sales, including the reliability purchases, decreased approximately $0.1 million, $6.1 million, and $8.4 million for the three, nine, and twelve months ended September 30, 2011 compared to the corresponding periods in 2010. Off-system sales margins also decreased due to the increased sharing of off-system sales margins with customers and lower average market prices for power.

Table of Contents

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

			Increase (Decrease)			
Quarter Ended September 30:	2011	2010	Amount	Percent		
kWh sales:						
Retail:						
Residential	899,708	819,294	80,414	9.8	%	
Commercial and industrial, small	703,479	676,894	26,585	3.9		
Commercial and industrial, large	279,339	300,845	(21,506)	(7.1)		
Sales to public authorities	452,370	450,895	1,475	0.3		
Total retail sales	2,334,896	2,247,928	86,968	3.9		
Wholesale:						
Sales for resale	21,046	17,019	4,027	23.7		
Off-system sales	726,753	804,558	(77,805)	(9.7)		
Total wholesale sales	747,799	821,577	(73,778)	(9.0)		
Total kWh sales	3,082,695	3,069,505	13,190	0.4		
Operating revenues:						
Non-fuel base revenues:						
Retail:						
Residential	$82,465	$75,411	$7,054	9.4	%	
Commercial and industrial, small	64,929	61,857	3,072	5.0		
Commercial and industrial, large	13,597	13,126	471	3.6		
Sales to public authorities	31,570	28,601	2,969	10.4		
Total retail non-fuel base revenues	192,561	178,995	13,566	7.6		
Wholesale:						
Sales for resale	387	646	(259)	(40.1)		
Total non-fuel base revenues	192,948	179,641	13,307	7.4		
Fuel revenues:						
Recovered from customers during the period	49,636	52,600	(2,964)	(5.6)		(1)
Under (over) collection of fuel	3,786	(9,703)	13,489	—		
New Mexico fuel in base rates	23,626	22,312	1,314	5.9		
Total fuel revenues	77,048	65,209	11,839	18.2		(2)
Off-system sales:						
Fuel cost	23,258	26,119	(2,861)	(11.0)		
Shared margins	1,310	1,879	(569)	(30.3)		
Retained margins	157	223	(66)	(29.6)		
Total off-system sales	24,725	28,221	(3,496)	(12.4)		
Other	12,912	7,271	5,641	77.6		(3)
Total operating revenues	$307,633	$280,342	$27,291	9.7		
Average number of retail customers:						
Residential	336,738	332,920	3,818	1.1	%	
Commercial and industrial, small	38,292	36,150	2,142	5.9		
Commercial and industrial, large	51	48	3	6.3		
Sales to public authorities	4,637	4,420	217	4.9		
Total	379,718	373,538	6,180	1.7		

(1) Excludes $11.5 million refund in 2010 related to prior periods' Texas deferred fuel revenues.

(2) Includes deregulated Palo Verde Unit 3 revenues for the New Mexico jurisdiction of $3.8 million and $3.9 million, respectively.

(3) Represents revenues with no related kWh sales. 2011 includes $4.5 million related to the settlement of a transmission dispute with Tucson Electric Power Company.

Table of Contents

			Increase (Decrease)		
Nine Months Ended September 30:	2011	2010	Amount	Percent	
kWh sales:					
Retail:					
Residential	2,078,247	1,958,670	119,577	6.1 %	
Commercial and industrial, small	1,816,081	1,762,224	53,857	3.1	
Commercial and industrial, large	817,549	826,553	(9,004)	(1.1)	
Sales to public authorities	1,200,597	1,180,222	20,375	1.7	
Total retail sales	5,912,474	5,727,669	184,805	3.2	
Wholesale:					
Sales for resale	52,045	43,534	8,511	19.6	
Off-system sales	2,162,793	2,163,766	(973)	—	
Total wholesale sales	2,214,838	2,207,300	7,538	0.3	
Total kWh sales	8,127,312	7,934,969	192,343	2.4	
Operating revenues:					
Non-fuel base revenues:					
Retail:					
Residential	$186,376	$170,399	$15,977	9.4 %	
Commercial and industrial, small	155,203	148,294	6,909	4.7	
Commercial and industrial, large	34,703	33,947	756	2.2	
Sales to public authorities	74,588	66,703	7,885	11.8	
Total retail non-fuel base revenues	450,870	419,343	31,527	7.5	
Wholesale:					
Sales for resale	1,722	1,520	202	13.3	
Total non-fuel base revenues	452,592	420,863	31,729	7.5	
Fuel revenues:					
Recovered from customers during the period	109,171	135,881	(26,710)	(19.7)	(1)
Under (over) collection of fuel	17,524	(21,795)	39,319	—	
New Mexico fuel in base rates	57,151	55,894	1,257	2.2	
Total fuel revenues	183,846	169,980	13,866	8.2	(2)
Off-system sales:					
Fuel cost	60,777	75,642	(14,865)	(19.7)	
Shared margins	2,722	3,600	(878)	(24.4)	
Retained margins	(697)	5,392	(6,089)	—	
Total off-system sales	62,802	84,634	(21,832)	(25.8)	
Other	27,110	20,430	6,680	32.7	(3)
Total operating revenues	$726,350	$695,907	$30,443	4.4	
Average number of retail customers:					
Residential	335,792	331,210	4,582	1.4 %	
Commercial and industrial, small	37,484	36,479	1,005	2.8	
Commercial and industrial, large	50	49	1	2.0	
Sales to public authorities	4,675	4,695	(20)	(0.4)	
Total	378,001	372,433	5,568	1.5	

(1) Excludes $12.0 million and $23.3 million of refunds in 2011 and 2010, respectively, related to prior periods' Texas deferred fuel revenues.

(2) Includes deregulated Palo Verde Unit 3 revenues for the New Mexico jurisdiction of $11.6 million and $13.2 million, respectively.

(3)

Represents revenues with no related kWh sales. 2011 includes $4.1 million related to the settlement of a transmission dispute with Tucson Electric Power Company.

Table of Contents

Twelve Months Ended September 30:	2011	2010	Increase (Decrease) Amount	Percent	
kWh sales:					
Retail:					
Residential	2,628,411	2,482,405	146,006	5.9 %	
Commercial and industrial, small	2,349,394	2,287,337	62,057	2.7	
Commercial and industrial, large	1,078,409	1,094,406	(15,997)	(1.5)	
Sales to public authorities	1,562,764	1,535,806	26,958	1.8	
Total retail sales	7,618,978	7,399,954	219,024	3.0	
Wholesale:					
Sales for resale	62,148	53,292	8,856	16.6	
Off-system sales	2,821,759	2,751,628	70,131	2.5	
Total wholesale sales	2,883,907	2,804,920	78,987	2.8	
Total kWh sales	10,502,885	10,204,874	298,011	2.9	
Operating revenues:					
Non-fuel base revenues:					
Retail:					
Residential	$233,592	$213,100	$20,492	9.6 %	
Commercial and industrial, small	195,299	190,053	5,246	2.8	
Commercial and industrial, large	44,600	42,825	1,775	4.1	
Sales to public authorities	94,345	85,088	9,257	10.9	
Total retail non-fuel base revenues	567,836	531,066	36,770	6.9	
Wholesale:					
Sales for resale	2,145	1,922	223	11.6	
Total non-fuel base revenues	569,981	532,988	36,993	6.9	
Fuel revenues:					
Recovered from customers during the period	143,878	174,681	(30,803)	(17.6)	(1)
Under (over) collection of fuel	3,911	(28,724)	32,635	—	
New Mexico fuel in base rates	73,133	71,945	1,188	1.7	
Total fuel revenues	220,922	217,902	3,020	1.4	(2)
Off-system sales:					
Fuel cost	78,651	98,777	(20,126)	(20.4)	
Shared margins	5,236	4,474	762	17.0	
Retained margins	(402)	8,017	(8,419)	—	
Total off-system sales	83,485	111,268	(27,783)	(25.0)	
Other	33,306	26,762	6,544	24.5	(3)
Total operating revenues	$907,694	$888,920	$18,774	2.1	
Average number of retail customers:					
Residential	335,306	330,434	4,872	1.5 %	
Commercial and industrial, small	37,289	36,441	848	2.3	
Commercial and industrial, large	50	49	1	2.0	
Sales to public authorities	4,686	4,760	(74)	(1.6)	
Total	377,331	371,684	5,647	1.5	

(1) Excludes $23.5 million and $28.5 million of refunds in 2011 and 2010, respectively, related to prior periods' Texas deferred fuel revenues.

(2) Includes deregulated Palo Verde Unit 3 revenues for the New Mexico jurisdiction of $14.5 million and $17.2 million, respectively.

(3)

Represents revenues with no related kWh sales. 2011 includes $3.9 million related to the settlement of a transmission dispute with Tucson Electric Power Company.

Table of Contents

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 35% of our available net generating capacity and approximately 49%, 55% and 56% of our Company-generated energy for the three, nine and twelve months ended September 30, 2011, respectively. 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 increased $10.4 million, or 11.7%, for the three months ended September 30, 2011 when compared to 2010 primarily due to (i) increased natural gas costs of $10.2 million as a result of a 24.3% increase in MWhs generated with natural gas, (ii) increased coal expense of $1.8 million primarily due to a favorable adjustment related to a contract renegotiation in 2010 and an increase in the average cost of coal; and (iii) increased nuclear fuel costs of $0.7 million as a result of a 10.9% increase in the price of nuclear fuel partially offset by a 3.9% decrease in MWhs generated with nuclear fuel. This increase was partially offset by decreased purchased power of $2.4 million due to a 19.9% decrease in the MWhs purchased partially offset by a 14.3% increase in the average market price for power purchased. The table below details the sources and costs of energy for the three months ended September 30, 2011 and 2010.

	Three Months Ended September 30,					
	2011			2010		
Fuel Type	Cost	MWh	Cost per MWh	Cost	MWh	Cost per MWh
	(in thousands)			(in thousands)		
Natural gas	$57,526	1,190,045	$48.34	$47,278	957,079	$49.40
Coal	3,614	174,628	20.70	1,861	173,298	10.74
Nuclear	11,894	1,322,790	8.99	11,155	1,375,883	8.11
Total	73,034	2,687,463	27.18	60,294	2,506,260	24.06
Purchased power	25,845	616,113	41.95	28,229	768,878	36.71
Total energy	$98,879	3,303,576	29.93	$88,523	3,275,138	27.03

Our energy expenses increased $1.0 million, or 0.4%, for the nine months ended September 30, 2011 when compared to 2010 primarily due to (i) increased natural gas costs of $7.7 million as a result of an increase in MWhs generated with natural gas; (ii) increased nuclear fuel costs of $4.8 million due to a 14.3% increase in the average cost of nuclear fuel and a 2.3% increase in the MWhs generated with nuclear fuel; (iii) increased coal costs of $4.4 million due to a $2.3 million adjustment for the amortization of final coal reclamation costs in accordance with the final order in PUCT Docket No. 38361, a favorable adjustment related to a contract renegotiation in 2010, an increase in the average cost of coal, and a 5.5% increase in the MWhs generated with coal. These increases were partially offset by decreased purchased power costs of $16.0 million as a result of a 12.9% decrease in the MWhs purchased and a 9.2% decrease in the market prices for power purchased. The table below details the sources and costs of energy for the nine months ended September 30, 2011 and 2010.

	Nine Months Ended September 30,					
	2011			2010		
Fuel Type	Cost (1)	MWh	Cost per MWh	Cost	MWh	Cost per MWh
	(in thousands)			(in thousands)		
Natural gas	$131,708	2,663,827	$50.63	$123,976	2,276,456	$54.46
Coal	12,030	486,607	24.72	7,630	461,332	16.54
Nuclear	33,373	3,834,651	8.70	28,533	3,748,164	7.61
Total	177,111	6,985,085	25.81	160,139	6,485,952	24.69
Purchased power	60,616	1,677,081	36.14	76,628	1,924,621	39.81

Total energy	$237,727	8,662,166	27.81	$236,767	8,410,573	28.15

(1) Natural gas costs exclude $3.2 million of energy expenses capitalized related to Newman Unit 5 pre-commercial testing.

Our energy expenses decreased $12.8 million, or 4.2%, for the twelve months ended September 30, 2011 when compared to 2010 primarily due to decreased purchased power costs of $23.8 million as a result of a 13.1% decrease in the MWhs purchased

Table of Contents

and a 12.3% decrease in the market prices for power. These decreases were partially offset by (i) increased nuclear fuel costs of $5.3 million due to a 9.7% increase in the average cost of nuclear fuel and a 5.1% increase in the MWhs generated with nuclear fuel, (ii) increased coal costs of $4.8 million due to a $2.2 million adjustment for the amortization of final coal reclamation costs in accordance with the final order in PUCT Docket No. 38361, a favorable adjustment related to a contract renegotiation in 2010, an increase in the average cost of coal, and a 3.7% increase in the MWhs generated with coal, and (iii) increased natural gas costs of $0.9 million as a result of an increase in MWhs generated with natural gas offset by a 10.4% decrease in the average cost of natural gas. The table below details the sources and costs of energy for the twelve months ended September 30, 2011 and 2010.

	Twelve Months Ended September 30,					
	2011			2010		
Fuel Type	Cost (1)	MWh	Cost per MWh	Cost	MWh	Cost per MWh
	(in thousands)			(in thousands)		
Natural gas	$161,300	3,277,481	$50.18	$160,425	2,865,276	$55.99
Coal	15,411	675,511	22.81	10,633	651,479	16.32
Nuclear	40,090	5,011,800	8.00	34,791	4,770,868	7.29
Total	216,801	8,964,792	24.54	205,849	8,287,623	24.84
Purchased power	75,904	2,173,329	34.93	99,660	2,501,675	39.84
Total energy	$292,705	11,138,121	26.56	$305,509	10,789,298	28.32

(1) Natural gas costs exclude $3.2 million of energy expenses capitalized related to Newman Unit 5 pre-commercial testing.

Other operations expense

Other operations expense decreased $3.1 million, or 5.2%, for the three months ended September 30, 2011 compared to the same period last year primarily due to (i) decreased accretion expense of $1.1 million related to the Palo Verde license extension for the Palo Verde asset retirement obligation, and (ii) decreased retirement and benefits costs associated with changes in the structure of medical benefits.

Other operations expense increased $6.6 million, or 4.1%, for the nine months ended September 30, 2011 compared to the same period last year primarily due to (i) increased administrative and general expense of $3.5 million relating to increased outside services due to regulatory activities, additional outside services related to software systems support and improvements, and increased amortization of rate case expenses, (ii) an increase in Palo Verde operations expense of $2.0 million, and (iii) an increase of $1.6 million in transmission and distribution expense relating to expense incurred to comply with specific NERC Critical Infrastructure Protection recommendations and increased wheeling expense.

Other operations expense increased $8.3 million, or 3.7%, for the twelve months ended September 30, 2011 compared to the same period last year primarily due to (i) increased customer accounts and service expense of $2.9 million primarily related to increased uncollectible customer accounts and costs incurred during the transition to a new customer billing system, (ii) an increase of $2.9 million in transmission and distribution expense relating to expense incurred to comply with specific NERC Critical Infrastructure Protection recommendations and increased wheeling expense, (iii) increased administrative and general expense of $2.3 million resulting from increased outside services due to regulatory activities, additional outside services related to software systems support and improvements, and increased amortization of rate case expenses partially offset by decreased retirement and benefit costs associated with changes in the structure of medical benefits.

Maintenance expense

Maintenance expense increased $1.8 million, or 16.2%, for the three months ended September 30, 2011 compared to the same period last year primarily due to the timing of routine maintenance expense at our coal and gas-fired generating plants. Maintenance expense increased $0.5 million, or 1.3%, for the nine months ended September 30, 2011 compared to the same period last year primarily due to maintenance expense at our local gas-fired generating plants largely as a result of weather-related damage during severe winter weather in February 2011, offset by decreased maintenance expense at Palo Verde and Four Corners. Maintenance expense decreased $1.5 million, or 2.6%, for the twelve months ended September 30, 2011 compared to the same periods last year primarily due to decreased Palo Verde maintenance expenses partially offset by increased maintenance expense at our coal and gas-fired generating plants.

Depreciation and amortization expense

Depreciation and amortization expense decreased $0.4 million, or 1.8%, for the three months ended September 30, 2011

Table of Contents

compared to the same periods last year primarily due to a reduction in depreciation rates related to the Palo Verde plant resulting from the approval of a license extension for Palo Verde by the NRC in April 2011, partially offset by increases in depreciable plant balances. Depreciation and amortization expense increased $0.6 million and $2.1 million, or 1.1% and 2.7%, for the nine and twelve months ended September 30, 2011 compared to the same periods last year primarily due to increases in depreciable plant balances and higher non-nuclear depreciation rates, partially offset by the reduction in depreciation rates stemming from the NRC license extension for Palo Verde.

Taxes other than income taxes

Taxes other than income taxes increased $0.5 million, or 3.1%, for the three months ended September 30, 2011 compared to the same period last year due to higher revenue-related taxes in Texas resulting from an increase in billed revenues and an increase in payroll taxes, which were partially offset by decreased property taxes due to a decrease in property tax rates in Arizona.

Taxes other than income taxes increased $2.1 million, or 5.1%, for the nine months ended September 30, 2011 compared to the same period last year due to increased property taxes as a result of an increase in taxable property and property tax rates, higher revenue-related taxes in Texas resulting from an increase in billed revenues, and an increase in the franchise tax rate for the City of El Paso in August 2010.

Taxes other than income taxes increased $4.2 million, or 8.0%, for the twelve months ended September 30, 2011 compared to the same period last year due to higher revenue-related taxes in Texas resulting from an increase in billed revenues and an increase in the franchise tax rate for the City of El Paso in August 2010, and increased property taxes due to an increase in taxable property and property tax rates.

Other income (deductions)

Other income (deductions) decreased $2.1 million for the three months ended September 30, 2011 compared to the same period last year due to decreased allowance for equity funds used during construction (“AEFUDC”) as a result of lower balances of construction work in progress and decreased investment and interest income. Other income (deductions) decreased $0.7 million for the nine months ended September 30, 2011 compared to the same period last year due to decreased AEFUDC as a result of lower balances of construction work in progress. Other income (deductions) decreased $1.9 million for the twelve months ended September 30, 2011 compared to the same period last year primarily due to increased donations.

Interest charges (credits)

Interest charges (credits) increased $1.1 million and $2.1 million for the three and nine months ended September 30, 2011 compared to the same periods last year primarily due to decreased allowance for borrowed funds used during construction as a result of lower balances of construction work in progress and increased commitment fees on our revolving credit facility. Interest charges (credits) increased $1.7 million for the twelve months ended September 30, 2011 compared to the same period last year primarily due to increased commitment fees on our revolving credit facility and an increase in amortization of loss on reacquired debt as allowed in the PUCT Docket No. 37690 which became effective July 1, 2010. See extraordinary item discussion below.

Income tax expense

Income tax expense, before extraordinary item, increased $6.5 million, or 23.9%, for the three months ended September 30, 2011 compared to the same period last year primarily due to increased pre-tax income. Income tax expense, before extraordinary item, increased by $1.6 million, or 3.1%, for the nine months ended September 30, 2011 and $0.1 million, or 0.3%, for the twelve months ended September 30, 2011 compared to the same period last year primarily due to increased pre-tax income partially offset by the recognition of the impact of the tax deduction for the Medicare Part D subsidies from the Patient Protection and Affordable Care Act in March 2010 with no comparable amount for 2011.

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 statements of operations for the quarter ended September 30, 2010. This item was recorded as a regulatory asset at 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.

Table of Contents

New Accounting Standards

In June 2011, the FASB issued new guidance to improve the comparability, consistency, and transparency of financial reporting and to increase the prominence of items reported in other comprehensive income. The new guidance requires an entity to present the total of comprehensive income either in a single continuous statement of comprehensive income or in two separate but consecutive statements. In both presentations, an entity is required to present on the face of the financial statements reclassification adjustments for items that are reclassified from other comprehensive income to net income in the statement(s) where the components of net income and the components of other comprehensive income are presented. Historically, we have used the consecutive two-statement approach; however, this new guidance will require additional disclosure on our statement of operations and related notes. The new guidance is required to be applied retrospectively and is effective for fiscal years, and interim periods within those years, beginning after December 15, 2011.

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 was adopted during the first quarter of 2011. During the three, nine and twelve months ended September 30, 2011, we had no purchases, sales, issuances or settlements in the Level 3 category. 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 minimal impact on our results of operations and financial condition.

Liquidity and Capital Resources

We continue to maintain a strong balance of common stock equity in our capital structure which allows us to obtain financing from the capital markets at a reasonable cost. At September 30, 2011, our capital structure, including common stock, long-term debt and current maturities of long-term debt, and short-term borrowings under the revolving credit facility, consisted of 48.4% common stock equity and 51.6% debt. At September 30, 2011, we had on hand $7.7 million in cash and cash equivalents.

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, operating expenses including fuel costs, maintenance costs, dividends and taxes.

Capital Requirements. During the nine months ended September 30, 2011, our capital requirements primarily consisted of expenditures for the construction and purchase of electric utility plant, purchases of nuclear fuel, the repurchase of common stock, and payment of common stock dividends. Projected utility construction expenditures are to expand and update our transmission and distribution systems, add new generation, and make capital improvements and replacements at Palo Verde and other generating facilities. Newman Unit 5, a 288 MW gas-fired combined cycle combustion turbine generating unit, was completed in two phases. The first phase of Newman Unit 5 was completed in May 2009, and the second phase was completed in April 2011. As of September 30, 2011, we had expended $235 million on Newman Unit 5, including $25.2 million during 2011. These amounts included AFUDC. Estimated construction expenditures for all capital projects for 2011 are approximately $178.5 million, and we expect cash from operations to continue to be a primary source of funds for these capital expenditures. See Part I, Item 1, "Business – Construction Program" in our 2010 Form 10-K. Cash capital expenditures for new electric plant were $129.7 million in the nine months ended September 30, 2011 compared to $124.8 million in the nine months ended September 30, 2010.

On September 30, 2011, we paid $9.2 million of quarterly dividends to shareholders. We have paid a total of $18.4 million in cash dividends during the nine months ended September 30, 2011. We expect to pay cash dividends totaling approximately $27.6 million during 2011. In addition, we may repurchase common stock in the future. Since 1999, we have returned cash to stockholders through a stock repurchase program pursuant to which we have bought approximately 25.1 million shares of common stock at an aggregate cost of $414.4 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 March 21, 2011, the Board of Directors authorized repurchases of up to 2.5 million additional shares of the Company’s outstanding common stock (the “2011 Plan”). During the first nine months of 2011, we repurchased 2,502,066 shares of common stock in the open market at an aggregate cost of $77.3 million. During the third quarter of 2011, 1,591,317 shares were repurchased at an aggregate cost of $51.0 million, including $12.5 million related to transactions that were not settled at September 30, 2011. As of September 30, 2011, 674,205 shares remain available for repurchase under our 2011 Plan.

We continue to utilize a combination of dividends and share repurchases to return capital to our shareholders, while maintaining a balanced capital structure. We will also continue to maintain a prudent level of liquidity as well as take market conditions for debt and equity securities into account. With the initiation of a dividend in early 2011, we are moving toward primarily utilizing the dividend to maintain a balanced capital structure, supplemented by share repurchases when appropriate. Our current expectation is that our payout ratio will trend upward from its current level, with a payout ratio of approximately 45% being the anticipated target for 2012. Our liquidity needs can fluctuate quickly based on fuel prices and other factors and we are continuing to make investments in new electric plant and other assets in order to reliably serve our customers. In light of these factors, we expect it will be a number of years before we achieve a dividend payout equivalent to industry average.

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 have been and 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 $13.4 million of the projected $13.9 million 2011 annual contribution to our retirement plans during the nine months ended September 30, 2011. In the nine months ended September 30, 2011, we contributed $2.2 million to fund our OPEB plan for the entire year of 2011, and $6.4 million of the projected $8.5 million 2011 annual contribution to our decommissioning trust funds. We are in compliance with the funding requirements of the federal government for our benefit plans and decommissioning trust.

Capital Resources. During the nine months ended September 30, 2011, we had increased cash from operations when compared to the same period in 2010 which reflects the increase in net income before a non-cash extraordinary gain in 2010. Cash flows were also impacted by an increase in deferred income taxes, offset by the timing of collection of fuel revenues to recover actual fuel expenses in 2011 compared to 2010. During the nine months ended September 30, 2011, we had an under-recovery of fuel costs, net of refunds, of $29.6 million, compared to an under-recovery, net of refunds, of $1.3 million during the nine months ended September 30, 2010. At September 30, 2011, we had a net fuel under-recovery balance of $10.6 million, including an under-recovery balance of $12.2 million in Texas partially offset by an over-recovery balance of $1.6 million in New Mexico.

Cash from operations has 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 at least four months after our last revision except in the month of December based upon our approved formula which allows us to adjust fuel rates to reflect changes in costs of natural gas.

On October 4, 2011, the El Paso City Council (the “City”) adopted a resolution ordering us to show cause why our base rates for electric service within the city limits of El Paso should not be lowered (the “Show Cause Order”) which we has appealed as discussed below. Pursuant to the Show Cause Order, we would be required to file a rate case with the City no later than February 1, 2012. The City would then have until the 185th day after the date that we file our rate case to make a determination regarding our base rates in El Paso. If we are ultimately required to file a rate case with the City for rates inside the city limits, we plan to simultaneously file a rate case with the other cities in our Texas service area and with the Public Utility Commission of Texas (the "PUCT") for rates outside any city limits.

The City conducted a hearing on temporary rates on October 25, 2011, and has scheduled an additional hearing for November 15, 2011. The revenues collected under temporary rates, if any, are subject to true-up to higher final rates approved by the PUCT and could be subject to refund if final rates are lower than temporary rates and a refund is authorized by the PUCT. The ultimate authority to set our Texas electric rates is vested in the PUCT.

On October 27, 2011, we filed an appeal with the PUCT to set aside the City's Show Cause Order or in the alternative issue an order staying the City's Show Cause Order and corresponding jurisdictional deadlines until the City can establish that it has complied with Texas statutes. We intend to vigorously defend our rates, which were lawfully approved only last year by the City and the PUCT as just and reasonable. If the City succeeds in implementing lower rates, the resulting lower rates would have a negative impact on our revenues, net income, and cash from operations. We cannot predict the outcome of this matter and we are unable to predict the effect, if any, this would have on our future operations, cash flows, and financial condition.

We maintain a $200 million revolving credit facility for working capital and general corporate purposes and the financing of nuclear fuel through the Rio Grande Resources Trust (“RGRT”). RGRT is the trust through which we finance our portion of

Table of Contents

nuclear fuel for Palo Verde and is consolidated in our financial statements. The revolving credit facility has a term ending in September 2014. The total amount borrowed for nuclear fuel by RGRT was $127.8 million at September 30, 2011 of which $17.8 million had been borrowed under the revolving credit facility and $110 million was borrowed through senior notes. At September 30, 2010, the total amounts borrowed for nuclear fuel by RGRT was $124.1 million of which $14.1 million was borrowed under the revolving credit facility and $110 million was borrowed through senior notes. Interest costs on borrowings to finance nuclear fuel are accumulated by RGRT and charged to us as fuel is consumed and recovered from customers through fuel recovery charges. No borrowings were outstanding at September 30, 2011under the revolving credit facility for working capital and general corporate purposes.

We believe we have adequate liquidity through our current cash balances, cash from operations, and our revolving credit facility to meet all of our anticipated cash requirements for the next twelve months. In addition, we may seek to issue long-term debt in the capital markets to finance capital requirements.

In October 2011, we received approval from the NMPRC and the FERC to amend and restate our $200 million revolving credit facility, which includes an option, subject to lenders' approval, to expand the size to $300 million, and to incrementally issue up to $300 million of long-term debt as and when needed. The amended and restated revolving credit facility will reduce our borrowing costs and extend the maturity from September 2014 to September 2016. Obtaining the ability to issue up to $300 million of new long-term debt, from time to time, provides us with the flexibility to access the debt capital markets when needed and when conditions are favorable.

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 3. Quantitative and Qualitative Disclosures About Market Risk

We are exposed to market risk due to changes in interest rates, equity prices and commodity prices. See our 2010 Form 10-K, Item 7A, “Quantitative and Qualitative Disclosures About Market Risk,” for a complete discussion of the market risks we face and our market risk sensitive assets and liabilities. As of September 30, 2011, there have been no material changes in the market risks we face or the fair values of assets and liabilities disclosed in Item 7A, “Quantitative and Qualitative Disclosures About Market Risk,” in our 2010 Form 10-K.

Item 4. 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 Exchange Act of 1934. Based on that evaluation, our chief executive officer and our chief financial officer concluded that, as of September 30, 2011, our disclosure controls and procedures are effective.

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 September 30, 2011, that materially affected, or that were reasonably likely to materially affect, our internal control over financial reporting.

Table of Contents

PART II. OTHER INFORMATION

Item 1. Legal Proceedings
We hereby incorporate by reference the information set forth in Part I of this report under Notes C and I of Notes to Consolidated Financial Statements.

Item 1A. Risk Factors
Our 2010 Form 10-K includes a detailed discussion of our risk factors.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

(c) Issuer Purchases of Equity Securities.

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
July 1 to July 31, 2011	—	$—	—	2,265,522
August 1 to August 31, 2011	142,867	32.32	142,867	2,122,655
September 1 to September 30, 2011	1,448,450	31.99	1,448,450	674,205

Item 6. Exhibits
See Index to Exhibits incorporated herein by reference.

Table of Contents

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

EL PASO ELECTRIC COMPANY

By: /s/ DAVID G. CARPENTER
David G. Carpenter
Senior Vice President - Chief Financial Officer
(Duly Authorized Officer and Principal Financial Officer)

Dated: November 4, 2011

Table of Contents

EL PASO ELECTRIC COMPANY
INDEX TO EXHIBITS

Exhibit Number	Exhibit
†10.05	Form of Directors' Restricted Stock Award Agreement between the Company and certain directors of the Company. (Identical in all material respects to Exhibit 10.07 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 1999)
15	Letter re Unaudited Interim Financial Information
31.01	Certifications pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.01	Certifications pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema Linkbase Document
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB	XBRL Taxonomy Extension Label Linkbase Document
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document

† In lieu of non-employee director cash compensation, three agreements, dated as of October 1, 2011, substantially identical in all material respects to this Exhibit, have been entered into with Catherine A. Allen; Patricia Z. Holland-Branch; and Stephen N. Wertheimer directors of the Company.