EL PASO ELECTRIC CO /TX/
Form 10-K
February 27, 2012

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

Form 10-K
(Mark One)

x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2011

OR

¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from to

Commission file number 001-14206

El Paso Electric Company
(Exact name of registrant as specified in its charter)

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

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

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

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

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

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. YES x NO ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). YES x NO ¨

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 126-2 of the Exchange Act.

Large accelerated filer	x	Accelerated filer	¨
Non-accelerated filer	o (Do not check if a smaller reporting company)	Smaller reporting company	¨

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

As of June 30, 2011, the aggregate market value of the voting stock held by non-affiliates of the registrant was $1,330,697,564 (based on the closing price as quoted on the New York Stock Exchange on that date).

As of January 31, 2012, there were 40,119,381 shares of the Company's no par value common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's definitive Proxy Statement for the 2012 annual meeting of its shareholders are incorporated by reference into Part III of this report.

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DEFINITIONS

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

Abbreviations, Acronyms or Defined Terms	Terms
ANPP Participation Agreement	Arizona Nuclear Power Project Participation Agreement dated August 23, 1973, as amended
APS	Arizona Public Service Company
ASU	Accounting Standards Updates
Company	El Paso Electric Company
DOE	United States Department of Energy
El Paso	City of El Paso, Texas
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Fort Bliss	Fort Bliss the United States Army post next to El Paso, Texas
Four Corners	Four Corners Generating Station
kV	Kilovolt(s)
kW	Kilowatt(s)
kWh	Kilowatt-hour(s)
Las Cruces	City of Las Cruces, New Mexico
MW	Megawatt(s)
MWh	Megawatt-hour(s)
NERC	North American Electric Reliability Corporation
NMPRC	New Mexico Public Regulation Commission
Net dependable generating capability	The maximum load net of plant operating requirements which a generating plant can supply under specified conditions for a given time interval, without exceeding approved limits of temperature and stress
NRC	Nuclear Regulatory Commission
Palo Verde	Palo Verde Nuclear Generating Station
Palo Verde Participants	Those utilities who share in power and energy entitlements, and bear certain allocated costs, with respect to Palo Verde pursuant to the ANPP Participation Agreement
PNM	Public Service Company of New Mexico
PUCT	Public Utility Commission of Texas
RGEC	Rio Grande Electric Cooperative
RGRT	Rio Grande Resources Trust II
TEP	Tucson Electric Power Company
TNP	Texas-New Mexico Power Company

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FORWARD-LOOKING STATEMENTS

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

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

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

- our rates in Texas following the rate case filed on February 1, 2012 pursuant to the El Paso City Council's resolution ordering us to show cause why our base rates for El Paso customers should not be lower,
- 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 us,
- 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 recovery mechanisms and other regulatory matters including the ability to recover fuel costs on a timely basis,
- changes in environmental laws and regulations and the enforcement or interpretation thereof, including those related to air, water or greenhouse gas emissions or other environmental matters,
- political, legislative, judicial and regulatory developments,

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- 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 post-retirement plan assets,
- 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 this document under the headings “Risk Factors” and “Management’s Discussion and Analysis” “–Summary of Critical Accounting Policies and Estimates” and “–Liquidity and Capital Resources.” This report should be read in its entirety. No one section of this report deals with all aspects of the subject matter. Any forward-looking statement speaks only as of the date such statement was made, and we are not obligated to update any forward-looking statement to reflect events or circumstances after the date on which such statement was made, except as required by applicable laws or regulations.

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PART I

Item 1. Business
General
El Paso Electric Company (the "Company") is a public utility engaged in the generation, transmission and distribution of electricity in an area of approximately 10,000 square miles in west Texas and southern New Mexico. The Company also serves a full requirements wholesale customer in Texas. The Company owns or has significant ownership interests in six electrical generating facilities providing it with a net dependable generating capability of approximately 1,785 MW. For the year ended December 31, 2011, the Company’s energy sources consisted of approximately 45% nuclear fuel, 30% natural gas, 6% coal, 19% purchased power and less than 1% generated by wind turbines.
The Company serves approximately 380,000 residential, commercial, industrial, public authority and wholesale customers. The Company distributes electricity to retail customers principally in El Paso, Texas and Las Cruces, New Mexico (representing approximately 63% and 11%, respectively, of the Company’s retail revenues for the year ended December 31, 2011). In addition, the Company’s wholesale sales include sales for resale to other electric utilities and power marketers. Principal industrial, public authority and other large retail customers of the Company include United States military installations, including Fort Bliss in Texas and White Sands Missile Range and Holloman Air Force Base in New Mexico, oil refining, two large universities, steel production and copper refining facilities.
The Company’s principal offices are located at the Stanton Tower, 100 North Stanton, El Paso, Texas 79901 (telephone 915-543-5711). The Company was incorporated in Texas in 1901. As of January 31, 2012, the Company had approximately 1,000 employees, 41% of whom are covered by a collective bargaining agreement.
The Company makes available free of charge through its website, www.epelectric.com, its annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and all amendments to those reports as soon as reasonably practicable after such material is electronically filed with or furnished to the Securities and Exchange Commission (“SEC”). In addition, copies of the annual report will be made available free of charge upon written request. The SEC also maintains an internet site that contains reports, proxy and information statements and other information for issuers that file electronically with the SEC. The address of that site is www.sec.gov. The information on the internet site is not incorporated into this document by reference.

Facilities
As of December 31, 2011, the Company’s net dependable generating capability of 1,785 MW consists of the following:

Station	Primary Fuel Type	Net Dependable Generating Capability * (MW)
Palo Verde Station	Nuclear	633
Newman Power Station	Natural Gas	752
Rio Grande Power Station	Natural Gas	229
Four Corners Station	Coal	108
Copper Power Station	Natural Gas	62
Hueco Mountain Wind Ranch	Wind	1
Total		1,785

* During summer peak period.

Palo Verde Station

The Company owns a 15.8% interest, or approximately 633 MW, in the three nuclear generating units and common facilities ("Common Facilities") at Palo Verde, in Wintersburg, Arizona. The Palo Verde Participants include the Company and six other utilities: APS, Southern California Edison Company ("SCE"), PNM, Southern California Public Power Authority, Salt River Project Agricultural Improvement and Power District ("SRP") and the Los Angeles Department of Water and Power. APS serves as operating agent for Palo Verde, and under the Arizona Nuclear Power Project ("ANPP") Participation Agreement, the Company has limited ability to influence operations and costs at Palo Verde.

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

NRC. The NRC regulates the operation of all commercial nuclear power reactors in the United States, including Palo Verde. The NRC periodically conducts inspections of nuclear facilities and monitors performance indicators to enable the agency to arrive at objective conclusions about a licensee's safety performance.

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 last three quarters of 2011 combined, the extension of the operating licenses had the effect of reducing depreciation and amortization expense by approximately $8.2 million and reducing the accretion expense on the Palo Verde asset retirement obligation by approximately $3.1 million.

Decommissioning. Pursuant to the ANPP Participation Agreement and federal law, the Company must fund its share of the estimated costs to decommission Palo Verde Units 1, 2 and 3, including the Common Facilities, through the term of their respective operating licenses. The Company is required to maintain a minimum accumulation and a minimum funding level in its decommissioning account at the end of each annual reporting period during the life of the plant. The Company has established external trusts with an independent trustee, which enables the Company to record a current deduction for federal income tax purposes for most of the amounts funded. At December 31, 2011, the Company's decommissioning trust fund had a balance of $168.0 million, and the Company was above its minimum funding level. The Company will continue to monitor the status of its decommissioning funds and adjust its deposits, if necessary, to remain at or above its minimum accumulation requirements in the future.

Decommissioning costs are estimated every three years based upon engineering cost studies performed by outside engineers retained by APS. On March 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 of $33.0 million (stated in 2010 dollars) from the 2007 Palo Verde decommissioning study (the "2007 Study"). The net effect of these changes lowered the asset retirement obligation by $41.7 million and will lower annual expenses in the future. 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. See "Spent Fuel Storage" and "Disposal of Low-Level Radioactive Waste" below.

Spent Fuel Storage. The original spent fuel storage facilities at Palo Verde had sufficient capacity to store all fuel discharged from normal operation of all three Palo Verde units through 2003. Alternative on-site storage facilities and casks have been constructed to supplement the original facilities. In March 2003, APS began removing spent fuel from the original facilities as necessary, and placing it in special storage casks which will be stored at the on-site facilities until accepted by the DOE for permanent disposal. The 2010 Study assumed that costs to store fuel on-site will become the responsibility of the DOE after 2057. APS believes that spent fuel storage or disposal methods will be available to allow each Palo Verde unit to continue to operate through the current term of its operating license.

Pursuant to the Nuclear Waste Policy Act of 1982, as amended in 1987 (the "Waste Act"), the DOE is legally obligated to accept and dispose of all spent nuclear fuel and other high-level radioactive waste generated by all domestic power reactors. In accordance with the Waste Act, the DOE entered into a spent nuclear fuel contract with the Company and all other Palo Verde Participants. The DOE has previously reported that its spent nuclear fuel disposal facilities would not be in operation in the near future. In November 1997, the United States Court of Appeals for the District of Columbia Circuit issued a decision preventing the DOE from excusing its own delay but refused to order the DOE to begin accepting spent nuclear fuel. The Company cannot predict when spent fuel shipments to the DOE will commence.

The Company expects to incur significant costs for on-site spent fuel storage during the life of Palo Verde that the Company believes are the responsibility of the DOE. These costs are assigned to fuel requiring the additional on-site storage and amortized as that fuel is burned until an agreement is reached with the DOE for recovery of these costs.
In December 2003, APS, in conjunction with other nuclear plant operators, filed suit against the DOE on behalf of the Palo Verde Participants to recover monetary damages associated with the delay in the DOE’s acceptance of spent fuel. APS pursued a damages claim for costs incurred through December 2006 in a trial that began on January 28, 2009. On June 18, 2010, the court

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awarded APS and the other Palo Verde Participants approximately $30 million. In October 2010, the Company received $4.8 million, representing its share of the award. The majority of the award was refunded to customers through the applicable fuel adjustment clauses. APS is continuing to pursue settlement of damage claims for costs incurred after 2006.

Disposal of Low-level Radioactive Waste. Congress has established requirements for the disposal by each state of low-level radioactive waste generated within its borders. The construction and opening of low-level radioactive waste disposal sites have been delayed due to extensive public hearings, disputes over environmental issues and review of technical issues related to the proposed sites. The opposition, delays, uncertainty and costs that have been experienced demonstrate possible roadblocks that may be encountered when Arizona seeks to open its own waste repository. APS currently believes that interim low-level waste storage methods are or will be available to allow each Palo Verde unit to continue to operate and to store safely low-level waste until a permanent disposal facility is available.

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.

Following the March 11, 2011 earthquake and tsunami in Japan, the NRC launched a two-pronged review of U.S. nuclear power plant safety. The NRC supported the establishment of an agency task force to conduct both a near- and long-term analysis of the lessons that can be learned from the situation in Japan. The near-term task force issued a report on July 12, 2011, and on October 3, 2011, the NRC staff issued a plan for implementing the near-term task force's recommendations.

On October 18, 2011, the NRC Commissioners directed the NRC staff to implement, without delay, the near-term task force recommendations, subject to certain conditions. One such condition is that the agency should strive to complete and implement lessons learned from the earthquake and tsunami in Japan within five years. A second condition is that the staff should designate the recommendation for a rulemaking to address extended loss of offsite power to be completed within 24 to 30 months.

Until further action is taken by the NRC as a result of this event, the Company cannot predict any financial or operational impacts on Palo Verde.

Liability and Insurance Matters. The Palo Verde participants have insurance for public liability resulting from nuclear energy hazards to the full limit of liability under federal law, which is currently at $12.6 billion. This potential liability is covered by primary liability insurance provided by commercial insurance carriers in the amount of $375 million, and the balance is covered by an industry-wide retrospective assessment program. If a loss at a nuclear power plant covered by the programs exceeds the accumulated funds in the primary level of protection, the Company could be assessed retrospective premium adjustments on a per incident basis. Under federal law, the maximum assessment per reactor under the program for each nuclear incident is approximately $117.5 million, subject to an annual limit of $17.5 million. Based upon the Company's 15.8% interest in the three Palo Verde units, the Company's maximum potential assessment per incident for all three units is approximately $55.7 million, with an annual payment limitation of approximately $8.3 million.

The Palo Verde Participants maintain “all risk” (including nuclear hazards) insurance for property damage to, and decontamination of, property at Palo Verde in the aggregate amount of $2.75 billion, a substantial portion of which must first be applied to stabilization and decontamination. The Company has also secured insurance against portions of any increased cost of generation or purchased power and business interruption resulting from a sudden and unforeseen outage of any of the three units. The insurance coverage discussed in this and the previous paragraph is subject to certain policy conditions and exclusions. A mutual insurance company whose members are utilities with nuclear facilities issues these policies. If losses at any nuclear facility covered by this mutual insurance company were to exceed the accumulated funds for these insurance programs, the Company could be assessed retrospective premium adjustments of up to $9.57 million for the current policy period.

Newman Power Station

The Company's Newman Power Station, located in El Paso, Texas, consists of three steam electric generating units and two combined cycle generating units, including a 278 MW combined cycle generating unit designated as Newman Unit 5. Construction of Newman Unit 5 began in July 2008 and was completed in two phases. The first phase, consisting of two 70 MW gas turbine generators, was completed in May 2009. The second phase consisted of the addition of two heat recovery steam generators and a steam turbine with a net peak period capability of 138 MW and was made commercially available in April 2011. The current aggregate net capability of the Newman Power Station is approximately 752 MW. The station operates primarily on natural gas but can also operate on fuel oil.

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Rio Grande Power Station

The Company's Rio Grande Power Station, located in Sunland Park, New Mexico, adjacent to El Paso, Texas, consists of three steam-electric generating units with an aggregate net peak period capability of approximately 229 MW. The units operate on natural gas. Construction has begun on Rio Grande Unit 9 to add an aeroderivative unit with a net dependable generating capacity of 87MW that should reach commercial operation by May 2013.

Four Corners Station

The Company owns a 7% interest, or approximately 108 MW, in Units 4 and 5 at Four Corners, located in northwestern New Mexico. Each of the two coal-fired generating units has a total net peak period capability of 770 MW. The Company shares power entitlements and certain allocated costs of the two units with APS (the Four Corners operating agent) and the other participants, PNM, TEP, SCE and SRP.

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

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

Copper Power Station

The Company’s Copper Power Station, located in El Paso, Texas, consists of a 62 MW combustion turbine used primarily to meet peak demand. The unit operates on natural gas.

Hueco Mountain Wind Ranch

The Company’s Hueco Mountain Wind Ranch, located in Hudspeth County, east of El Paso County and adjacent to Horizon City, currently consists of two wind turbines with a total capacity of 1.32 MW of which a portion, currently 10%, is used as net capability for resource planning purposes.

Transmission and Distribution Lines and Agreements

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

Springerville-Macho Springs-Luna-Diablo Line. The Company owns a 310-mile, 345 kV transmission line from TEP's Springerville Generating Plant near Springerville, Arizona, to the Company's Diablo Substation near Sunland Park, New Mexico. This line also contains two other substations; the Macho Springs Substation near Hatch, New Mexico, and the Luna Substation near Deming, New Mexico. This transmission line provides an interconnection with TEP for delivery of the Company's generation entitlements from Palo Verde and, if necessary, Four Corners. The Macho Springs Substation was commissioned in 2011 to interconnect a wind farm that provides renewable power to TEP.

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

Greenlee-Hidalgo-Luna-Newman Line. The Company owns 40% of a 60-mile, 345 kV transmission line between TEP's

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

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

Palo Verde Transmission and Switchyard. The Company owns 18.7% of two 45-mile, 500 kV lines from Palo Verde to the Westwing Substation located northwest of Phoenix near Peoria, Arizona. The Company also owns 18.7% of a 75-mile, 500 kV line from Palo Verde to the Jojoba Substation, then to the Kyrene Substation located near Tempe, Arizona. These lines provide the Company with a transmission path for delivery of power from Palo Verde. The Company owns 14.94% and 9.35% respectively of two 500 kV switchyards connected to the Palo Verde-Kyrene 500 kV line: the Hassayampa switchyard, adjacent to the southern edge of the Palo Verde 500 kV switchyard and the Jojoba switchyard approximately 24 miles from Palo Verde. These switchyards were built to accommodate the addition of new generation and transmission in the Palo Verde area.

Environmental Matters

General. The Company is subject to laws and regulations with respect to air, soil and water quality, waste disposal and other environmental matters by federal, state, regional, tribal and local authorities. Those authorities govern facility operations and have continuing jurisdiction over facility modifications. Failure to comply with these 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 liabilities. These laws and regulations are subject to change and, as a result of those changes, the Company may face additional capital and operating costs to comply. Certain key environmental issues, laws and regulations facing the Company are described further below.

Air Emissions. The U.S. Clean Air Act (“CAA”) and comparable state laws and regulations relating to air emissions impose, among other obligations, limitations on pollutants generated during the Company's operations, including sulfur dioxide (“SO2”), particulate matter (“PM”), 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, and such rule is binding. 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 (in thousands):

Compliance Year	Amount
2010	$370
2011	62

Cross-State Air Pollution Rule. In July 2011, the EPA finalized the Cross-State Air Pollution Rule (“CSAPR”) which is intended to replace CAIR. CSAPR requires 28 states, including Texas, to further reduce power plant emissions of SO_2 and NOx. Under CSAPR, reductions in annual SO_2 and NOx emissions were required to begin January 1, 2012, with further reductions required beginning January 1, 2014. On December 30, 2011, the U.S. Court of Appeals for the District of Columbia Circuit issued its ruling to stay CSAPR, including the supplemental final rule, pending judicial review, which delays CSAPR's implementation date beyond January 1, 2012. The court is scheduled to hear the cases against the rule in April 2012. Under this timeframe, the court could issue its decision by summer or early fall 2012. As the outcome of the judicial review and any other legal or Congressional challenges are uncertain, the Company is unable to determine what impact CSAPR may ultimately have on its operations and consolidated financial results, but it could be material. Until the legal challenges to CSAPR are resolved, the Company's obligations under CAIR remains in effect.

National Ambient Air Quality Standards. Under the CAA, the EPA sets National Ambient Air Quality Standards ("NAAQS") for six criteria emissions considered harmful to public health and the environment, including PM, NOx, CO and SO_2.

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Areas meeting the NAAQS are designated attainment areas while those that do not meet the NAAQS are considered nonattainment areas. Each state must develop a plan to bring nonattainment areas into compliance with the NAAQS. NAAQS must be reviewed by the EPA at five-year intervals. In 2010, the EPA strengthened the NAAQS for both NOx and SO_2. The Company is currently evaluating what impact this could have on its operations. If the Company is required to install additional equipment to control emissions at its facilities, the revised NAAQS could have a material impact on its operations and consolidated financial results. In addition, the EPA is currently reviewing the PM NAAQS. The Company cannot at this time predict the impact of this review and any possible new standards on its operations or consolidated financial results, but it could be material. The EPA had been in the process of revising the NAAQS for ozone. However, in September 2011, President Obama ordered the EPA to withdraw its proposal. Work, however, is underway to support EPA's planned reconsideration of the standards in 2013.

Utility MACT. The operation of coal-fired power plants, such as the Company's Four Corners plant, results in emissions of mercury and other air toxics. In December 2011, the EPA finalized Mercury and Air Toxics Standards (known as the "Utility MACT") for power plants, which replaces the prior federal Clean Air Mercury Rule and requires significant reductions in emissions of mercury and other air toxics. Companies impacted by the new standards will have up to four (and in certain cases five) years to comply. The Company is currently evaluating the new standards and cannot at this time determine the impact they may have on its Four Corners plant, but the cost of compliance 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 unlikely to recommence in the near future. 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, and other measures are being imposed or offered by individual states, municipalities and regional agreements with the goal of reducing 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 ("SF6"), another GHG. The Company is tracking these GHG emissions pursuant to the EPA's new SF6 reporting rule that was finalized in late 2010 and became effective January 1, 2011. The first report to EPA under this rule was originally due on March 31, 2012, but in November 2011, EPA delayed its submittal to September 26, 2012.

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”. Pursuant to the rule, the EPA may reduce the 75,000 tons threshold referenced above in 2012 or thereafter. 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, and certain agreed upon extensions, the EPA intends to issue proposed rules for new and modified electric generating units ("EGUs") in 2012. It is unclear when the EPA will propose a GHG New Source Performance Standard ("NSPS") for existing EGUs and how stringent it would be, but this rule is expected. 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.

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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 the Company's service area by causing higher temperatures, less winter precipitation and less spring runoff, as well as by causing more extreme weather events. Such developments could change the demand for power in the region and could also impact the price or ready availability of water supplies or affect maintenance needs and the reliability of Company equipment.

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

Contamination Matters. The Company has a provision for environmental remediation obligations of approximately $0.3 million at December 31, 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 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.

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. The EPA has taken the position that many utilities have made certain physical or operational changes at their plants that should have triggered additional regulatory requirements under the New Source Review provisions of the CAA. APS responded to this request in 2009. The Company is unable to predict the timing or content of the EPA's response, if any, or any resulting actions.

The Company received word that Earthjustice filed a lawsuit in the United States District Court for New Mexico on October 4, 2011 for alleged violations of the Prevention of Significant Deterioration provisions of the CAA. Subsequent to filing its original Complaint, on January 6, 2012, Earthjustice filed a First Amended Complaint adding claims for violations of the CAA's NSPS program. Among other things, the plaintiffs seek to have the court enjoin operations at Four Corners until APS applies for and obtains any required PSD permits and complies with the NSPS. The plaintiffs further request the court to order the payment of civil penalties, including a beneficial mitigation project. APS advised that it believes the claims in this matter are without merit and will vigorously defend against them. The Company is unable to predict the outcome of these alleged violations.

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Construction Program

Utility construction expenditures reflected in the following table consist primarily of local generation, expanding and updating the transmission and distribution systems, and the cost of capital improvements and replacements at Palo Verde. Studies indicate that the Company will need additional power generation resources to meet increasing load requirements on its system and to replace retiring plants, the costs of which are included in the table below. The Company's estimated cash construction costs for 2012 through 2016 are approximately $1.4 billion. Actual costs may vary from the construction program estimates shown. Such estimates are reviewed and updated periodically to reflect changed conditions.

By Year (1)(2) (in millions)		By Function (in millions)	
2012	$242	Production (1)(2)	$892
2013	232	Transmission	120
2014	267	Distribution	281
2015	311	General	96
2016	337		
Total	$1,389	Total	$1,389

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

(2) $700 million has been allocated for new generating capacity including $38 million to complete Rio Grande Unit 9, $186 million to construct two 87 MW gas-fired LMS-100 units that are scheduled to come on line in 2014 and 2015, $174 million for two 87 MW gas-fired LMS-100 units scheduled to come on line in 2016, and $284 million of initial expenditures for two additional 292 MW combined cycle generating units that are anticipated to come on line in 2018 and 2019 and $18 million for anticipated renewable projects to be built in El Paso. Total production expenditures also include $24 million for other local generation, $14 million for the Four Corners Station and $154 million for the Palo Verde Station.

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Energy Sources

General

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

	Years Ended December 31,					
Power Source	2011		2010		2009	
Nuclear	45	%	45	%	45	%
Natural gas	30		27		22	
Coal	6		6		7	
Purchased power	19		22		26	
Total	100	%	100	%	100	%

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

Nuclear Fuel

The nuclear fuel cycle for Palo Verde consists of the following stages: the mining and milling of uranium ore to produce uranium concentrates; the conversion of the uranium concentrates to uranium hexafluoride ("conversion services"); the enrichment of uranium hexafluoride ("enrichment services"); the fabrication of fuel assemblies ("fabrication services"); the utilization of the fuel assemblies in the reactors; and the storage and disposal of the spent fuel.

Pursuant to the ANPP Participation Agreement, the Company owns an undivided interest in nuclear fuel purchased in connection with Palo Verde. The Palo Verde participants are continually identifying their future nuclear fuel resource needs and negotiating arrangements to fill those needs. The Palo Verde participants have contracted for 95% of Palo Verde's requirements for uranium concentrates through 2015, 90% of its requirements in 2016-2017 and 80% of its requirements in 2018. The participants have also contracted for all of Palo Verde's conversion services through 2015 and 95% of its requirements in 2016-2018, all of Palo Verde's enrichment services through 2020 and all of Palo Verde's fuel assembly fabrication services through 2016.

Nuclear Fuel Financing. The Company’s financing of nuclear fuel is accomplished through Rio Grande Resources Trust (“RGRT”), a Texas grantor trust, which is consolidated in the Company’s financial statements. RGRT has $110 million aggregate principal amount borrowed through senior notes. The Company guarantees the payment of principal and interest on the senior notes. The nuclear fuel financing requirements of RGRT are met with a combination of the senior notes and amounts borrowed under the revolving credit facility (the “RCF”).

The Company maintains a $200 million RCF for the financing of nuclear fuel and for working capital and general corporate purposes. On November 15, 2011, the Company, along with RGRT, refinanced and extended the credit facility, which includes an option, subject to lenders' approval, to expand the size to $300 million. The amended facility reduces our borrowing costs and extends the maturity from September 2014 to September 2016. The total amount borrowed for nuclear fuel by RGRT at December 31, 2011 was $123.4 million of which $13.4 million had been borrowed under the RCF, and $110 million was borrowed through the senior notes. Interest costs on borrowings to finance nuclear fuel are accumulated by RGRT and charged to the Company as fuel is consumed and recovered from customers through fuel recovery charges.

Natural Gas

The Company manages its natural gas requirements through a combination of a long-term supply contract and spot market purchases. The long-term supply contract provides for firm deliveries of gas at market-based index prices. In 2011, the Company’s natural gas requirements at the Newman and Rio Grande Power Stations were met with both short-term and long-term natural gas purchases from various suppliers, and this practice is expected to continue in 2012. Interstate gas is delivered under a base firm transportation contract. The Company anticipates it will continue to purchase natural gas at spot market prices on a monthly basis for a portion of the fuel needs for the Newman and Rio Grande Power Stations. The Company will continue to evaluate the availability of short-term natural gas supplies versus long-term supplies to maintain a reliable and economical supply for the Newman and Rio Grande Power Stations.

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Natural gas for the Newman and Copper Power Stations is also supplied pursuant to an intrastate natural gas contract that became effective October 1, 2009 and continues through 2017. The intrastate natural gas agreement was amended effective September 1, 2010.

Coal

APS, as operating agent for Four Corners, purchases Four Corners' coal requirements from a supplier with a long-term lease of coal reserves owned by the Navajo Nation. In June 2010, the Four Corners coal contract was renegotiated with the coal supplier, resulting in reduced coal prices for the remaining term of the agreement. The Four Corners coal contract expires in mid-2016. Based upon information from APS, the Company believes that Four Corners has sufficient reserves of coal to meet the plant's operational requirements through mid-2016.

Purchased Power

To supplement its own generation and operating reserves and to meet required renewable portfolio standards, the Company engages in firm power purchase arrangements which may vary in duration and amount based on evaluation of the Company's resource needs, the economics of the transactions and specific renewable portfolio requirements.

The Company has a Power Purchase and Sale Agreement with Freeport-McMoran Copper and Gold Energy Services LLC ("Freeport") which provides for Freeport to deliver energy to the Company from its ownership interest in the Luna Energy Facility (a natural gas fired combined cycle generation facility located in Luna County, New Mexico) and for the Company to deliver a like amount of energy at Greenlee, Arizona. The Company may purchase up to 125 MW at a specified price at times when energy is not exchanged under the Power Purchase and Sale Agreement. Upon mutual agreement, the contract allows the parties to increase the amount of energy that is purchased and sold under the Power Purchase and Sale Agreement. The parties have agreed to increase the amount to 125 MW through December 2013. The contract was approved by the FERC and continues through December 31, 2021.

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

The Company entered into a 20-year contract with NRG Solar Roadrunner, LLC ("NRG") for the purchase of all of the output of a solar photovoltaic plant built in southern New Mexico which began commercial operation in August 2011. (See "Regulation - New Mexico Regulatory Matters.") The Company has a 25-year purchase power agreement with NextEra Energy Resource for a solar photovoltaic project located in southern New Mexico which began commercial operation in July 2011. The Company has 25-year purchase power agreements for two additional solar photovoltaic projects located in southern New Mexico, SunEdison 1 and SunEdison 2 which commercial operation is estimated to begin in 2012. The Company entered into these contracts to help meet its renewable portfolio requirements.

Other purchases of shorter duration were made during 2011 to supplement the Company's generation resources during planned and unplanned outages and for economic reasons as well as to supply off system sales.

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Operating Statistics

	Years Ended December 31,		
	2011	2010	2009
Operating revenues (in thousands):			
Non-fuel base revenues:			
Retail:			
Residential	$234,086	$217,615	$195,798
Commercial and industrial, small	196,093	188,390	175,328
Commercial and industrial, large	45,407	43,844	34,804
Sales to public authorities	94,370	86,460	77,370
Total retail base revenues	569,956	536,309	483,300
Wholesale:			
Sales for resale	2,122	1,943	2,037
Total non-fuel base revenues	572,078	538,252	485,337
Fuel revenues:			
Recovered from customers during the period	145,130	170,588	196,081
Under (over) collection of fuel	13,917	(35,408)	(66,608)
New Mexico fuel in base rates	73,454	71,876	69,026
Total fuel revenues	232,501	207,056	198,499
Off-system sales:			
Fuel cost	74,736	93,516	101,665
Shared margins	3,883	6,114	3,596
Retained margins	(560)	5,687	10,803
Total off-system sales	78,059	105,317	116,064
Other	35,375	26,626	28,096
Total operating revenues	$918,013	$877,251	$827,996
Number of customers (end of year):			
Residential	337,659	334,729	328,553
Commercial and industrial, small	37,942	37,202	36,306
Commercial and industrial, large	49	50	48
Other	4,596	4,841	4,964
Total	380,246	376,822	369,871
Average annual kWh use per residential customer	7,832	7,560	7,244
Energy supplied, net, kWh (in thousands):			
Generated	8,936,776	8,465,659	7,979,290
Purchased and interchanged	2,112,596	2,420,869	2,745,500
Total	11,049,372	10,886,528	10,724,790
Energy sales, kWh (in thousands):			
Retail:			
Residential	2,633,390	2,508,834	2,361,650
Commercial and industrial, small	2,352,218	2,295,537	2,251,399
Commercial and industrial, large	1,096,040	1,087,413	1,024,186
Sales to public authorities	1,579,565	1,542,389	1,482,448
Total retail	7,661,213	7,434,173	7,119,683
Wholesale:			
Sales for resale	62,656	53,637	56,931
Off-system sales	2,687,631	2,822,732	2,995,984
Total wholesale	2,750,287	2,876,369	3,052,915
Total energy sales	10,411,500	10,310,542	10,172,598

Losses and Company use	637,872	575,986	552,192
Total	11,049,372	10,886,528	10,724,790
Native system:			
Peak load, kW	1,711,000	1,616,000	1,571,000
Net dependable generating capability for peak, kW (1)	1,785,000	1,643,000	1,643,000
Total system:			
Peak load, kW (2)	1,965,000	1,889,000	1,723,000
Net dependable generating capability for peak, kW (1) (3)	1,785,000	1,643,000	1,643,000

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(1) 2011 includes a 138,000 kW increase in net generating capability at Newman related to the completion of the second phase of the Newman Unit 5 construction which consists of two heat recovery steam generators and a steam turbine.

(2) Includes spot sales and net losses of 254,000 kW, 273,000 kW and 152,000 kW for 2011, 2010 and 2009, respectively.

(3) Excludes spot firm purchases, as well as 65,000 kW, 100,000 kW and 233,000 kW for 2011, 2010 and 2009, respectively, of long-term firm on-peak purchases.

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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.

2012 Texas Retail Rate Case. The Company filed a request with the PUCT (Docket No. 40094), the City of El Paso, and other Texas cities on February 1, 2012 for a $26.3 million increase in rates charged to customers in Texas. The rate filing was made in response to a resolution adopted by the El Paso City Council requiring the Company to show cause why its base rates for customers in the El Paso city limits should not be reduced. The City has until August 4, 2012 to make a determination regarding the Company's base rates in the City of El Paso. The rate filing used a historical test year ended September 30, 2011, adjusted for known and measurable items, and a return on equity of 10.6%. The filing at the PUCT also includes a request to reconcile $356.5 million of fuel expense for the period July 1, 2009 through September 30, 2011.

On November 15, 2011, the El Paso City Council adopted a resolution which established current rates as temporary rates for the Company's customers residing within the city limits of El Paso. Temporary rates will be effective from November 15, 2011 until a final determination is made by the PUCT on the Company's rates in the rate proceeding initiated by the City's Show Cause Order. Upon a final determination by the PUCT, the PUCT may order a refund to customers of money collected in excess of the rate finally ordered, including interest, or shall authorize the Company to surcharge bills to recover the amount, including interest, by which the money collected under the temporary rates is less than the money that would have been collected under the rate finally ordered. The rates proposed by the Company in the Texas rate case included increases for some customer classes and decreases for other customer classes. As a result, consistent implementation of the proposed rates may require the PUCT to reflect the differences in temporary and final rates from November 15, 2011 for each affected class.

While cities in Texas have jurisdiction over rates in their city limits, the PUCT has appellate authority over city rate decisions on a "de novo" basis; therefore, the ultimate authority to set the Company's Texas electric rates is vested in the PUCT. The Company cannot predict the outcome of this proceeding. If the rate case results in implementing lower rates, the resulting lower rates would have a negative impact on the Company's revenues, net income and cash from operations.

Fuel Reconciliation Case (Severed from 2009 Rate Case). Pursuant to the stipulation in the Company's 2009 rate case, the PUCT established Docket No. 38361 to address the 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.

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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 which adjusts natural gas and purchased power to reflect natural gas futures prices. 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 billing month(s) in which customers received the refund amounts shown, including interest:

Docket No.	Date Filed	Date Approved	Recovery Period	Refund Period	Refund Amount (In thousands)
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

As noted above, the rate filing filed with the PUCT on February 1, 2012 (Docket No. 40094), includes a request to reconcile $356.5 million of fuel expense for the period July 1, 2009 through September 30, 2011. However, this filing does not request a change in the fixed fuel factor.

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. A final order was issued January 12, 2012 revising the MBDRF to 0.936% and allowing $3.9 million dollars of under-recovered discount charges to begin February 1, 2012.

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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. 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 passed a motion that, upon the conclusion of other hearings and investigations into the extreme cold weather event, the Mayor would call for Special City Council meetings or public hearings to evaluate how the three utility companies operating within the city, including the Company, performed during the extreme weather event. The El Paso City Council retained a consultant to assess the Company's activities during the weather event and the Company's subsequent actions to prevent outages during a similar future event. The El Paso City Council's consultant presented the following three recommendations to the El Paso City Council on December 20, 2011: (i) request the Company to prepare and present an updated reliability study; (ii) request the Company and El Paso Water Utilities to present their coordinated plans for power and water supply to critical loads during severe weather events; and (iii) request the Company to file an updated emergency operations plan with both the PUCT and the El Paso City Council which will be completed in 2012. The El Paso City Council unanimously passed a motion to approve the three recommendations. At the January 10, 2012 El Paso City Council Meeting, the Company presented information requested in recommendations (i) and (ii) above.

Application of El Paso Electric Company to Amend its Certificate of Convenience and Necessity for Five Solar Power Generation Projects. On December 9, 2011, the Company filed a petition seeking a CCN to construct five solar powered generation projects, totaling approximately 2.6 MW, at four locations within the City of El Paso and one location in the Town of Van Horn. This case was assigned PUCT Docket No. 39973 and is still pending.

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. A final order was issued on November 22, 2011 in which the NMPRC did not adopt the unopposed stipulation, but modified the structure of the energy rider to reduce the return to two percent and made the mechanism temporary. The Company filed a Notice of Appeal with the Supreme Court of the State of New Mexico on January 20, 2012 on the grounds that the NMPRC's decision is arbitrary and without substantial evidence.

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

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City of Sunland Park in southeast New Mexico. This case was assigned NMPRC Case No. 10-00301-UT. 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 January 25, 2012, a hearing examiner issued a recommended decision modifying the stipulation by approving the Energy Efficiency programs and budgets with the exception of the Commercial Lighting Program, approving the adder for 2011 but not for 2012 or 2013 and excluding the Military Research & Development Class from participation in the rate rider and reducing the Company's required saving goals accordingly. On February 2, 2012, the Company filed certain exceptions to the recommended decision and requested an interim order related to this matter.

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 Renewable Procurement 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 2011 Renewable Procurement 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. A final order was issued on December 15, 2011 approving the 2011 Renewable Procurement Plan.

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. Obtaining the ability to issue up to $300 million of new long-term debt, from time to time, provides the Company with the flexibility to access the debt capital markets when needed and when conditions are favorable.

On November 15, 2011, the Company and Rio Grande Resources Trust ("RGRT") amended and restated the $200 million unsecured RCF with JP Morgan Chase Bank, N.A., as administrative agent and issuing bank, and Union Bank, N.A., as syndication agent, and various lending banks party thereto. The amended and restated RCF reduces borrowing costs and extends the maturity from September 2014 to September 2016. The Company still has the ability to request that the RCF be increased to $300 million during the term of the RCF, subject to lender's approval. All other terms remain substantially the same.

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

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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 that 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. Those two new service agreements were entered into and became effective November 1, 2011. Also under the terms of the settlement, TEP made a lump-sum cash payment to the Company of approximately $5.4 million 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. As part of the settlement, the Company withdrew 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. As part of the settlement, this lawsuit was dismissed.

With the implementation of the settlement effective November 1, 2011, these matters between the Company and TEP were fully resolved.

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, where it made recommendations to help prevent a recurrence of such outages in the future, and making no finding of violations or assessments of penalties.

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. Obtaining the ability to issue up to $300 million of new long-term debt, from time to time, provides the Company with the flexibility to access the debt capital markets when needed and when conditions are favorable.

On November 15, 2011, the Company and Rio Grande Resources Trust ("RGRT") amended and restated the $200 million unsecured RCF with JP Morgan Chase Bank, N.A., as administrative agent and issuing bank, and Union Bank, N.A., as syndication agent, and various lending banks party thereto. The amended and restated RCF reduces borrowing costs and extends the maturity from September 2014 to September 2016. The Company still has the ability to request that the RCF be increased to $300 million,

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subject to lender's approval. All other terms remain substantially the same. See "Energy Sources - Nuclear Fuel - Nuclear Fuel Financing."

Department of Energy. The DOE regulates the Company's exports of power to the Comisión Federal de Electricidad in Mexico pursuant to a license granted by the DOE and a presidential permit.

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

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

Sales for Resale

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

Power Sales Contracts

The Company has entered into several short-term (three months or less) off-system sales contracts throughout 2012.

Franchises and Significant Customers

El Paso and Las Cruces Franchises

The Company has a franchise agreement with El Paso, the largest city it serves. The franchise agreement allows the Company to utilize public rights-of-way necessary to serve its retail customers within El Paso. The Company also provides electric distribution service to Las Cruces under an implied franchise by satisfying all obligations under the franchise agreement that expired April 30, 2009.

The franchise agreements held between the Company and the cities of El Paso and Las Cruces are detailed below:

City	Period	Franchise Fee	(a)
El Paso	July 1, 2005 - August 1, 2010	3.25%	
El Paso	August 1, 2010 - Present	4.00%	(b)
Las Cruces	February 1, 2000 - Present	2.00%	

(a) Based on a percentage of revenue.

(b) The additional fee of 0.75% is to be placed in a restricted fund to be used solely for economic development and renewable energy purposes.

Military Installations

The Company currently serves Holloman Air Force Base ("Holloman"), White Sands Missile Range ("White Sands") and Fort Bliss. The Company's sales to the military bases represent approximately 5% of annual retail revenues. The Company entered into a contract with Fort Bliss in October 2008, under which Fort Bliss takes retail electric service from the Company. The contract with Fort Bliss expired in 2010, and the Company is serving Fort Bliss under the applicable Texas tariffs. In April 1999, the Army and the Company entered into a ten-year contract to provide retail electric service to White Sands. The contract with White Sands expired in 2009, and the Company is serving White Sands under the applicable New Mexico tariffs. In March 2006, the Company signed a contract with Holloman for the Company to provide retail electric service and limited wheeling services to Holloman for a ten-year term expiring in January 2016.

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Item 1A. Risk Factors

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

Our Revenues and Profitability Depend upon Regulated Rates

Our retail rates are subject to regulation by incorporated municipalities in Texas, the PUCT, the NMPRC and the FERC. The settlement approved in the Company's 2009 Texas rate case, PUCT Docket No. 37690, established the Company's current retail base rates in Texas, effective July 1, 2010. In addition, the settlement in the Company's 2009 New Mexico rate case, NMPRC Case No. 09 00171 UT, established rates in New Mexico that became effective January 2010. On February 1, 2012, we filed a request with the PUCT (Docket No. 40094), the City of El Paso and other Texas cities, for a $26.3 million increase in rates charged to customers in Texas. The rate filing was made in response to a resolution adopted by the El Paso City Council requiring us to show cause why our base rates for customers in El Paso should not be reduced.

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

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

The construction of our next generating plant addition, Rio Grande Unit 9, will add an aeroderivative unit with a generating capacity of 87 MW. It should reach commercial operation by May 2013. We have risk related to recovering all costs associated with the completion of the construction of Rio Grande Unit 9 and other new units.

In 2011, we refinanced and extended our revolving credit facility which could help fund the construction of this and other new units. The costs of financing and constructing these units will be reviewed in future rate cases in both Texas and New Mexico. To the extent that the PUCT or NMPRC determines that the costs of construction are not reasonable because of cost overruns, delays or other reasons, we may not be allowed to recover these costs from customers in base rates.

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

Continuing Weakness in the Economy and Uncertainty in the Financial Markets Could Reduce Our Sales, Hinder Our Capital Programs and Increase Our Funding Obligations for Pensions and Decommissioning

In recent years, the global credit and equity markets and the overall economy have been through a state of turmoil. These and future events could have a number of effects on our operations and our capital programs. For example, tight credit and capital markets could make it difficult and more expensive to raise capital to fund our operations and capital programs. If we are unable to access the credit markets, we could be required to defer or eliminate important capital projects in the future. In addition, recent stock market performance has provided returns that are below historic average for our financial assets and decommissioning trust investments. Such market results may also increase our funding obligations for our pension plans, other post-retirement benefit plans and nuclear decommissioning trusts. Changes in the corporate interest rates which we use as the discount rate to determine our pension and other post-retirement liabilities may have an impact on our funding obligations for such plans and trusts. Further, the continued volatile economy may result in reduced customer demand, both in the retail and wholesale markets, and increases

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in customer delinquencies and write-offs. The credit markets and overall economy may also adversely impact the financial health of our suppliers. If that were to occur, our access to and prices for inventory, supplies and capital equipment could be adversely affected. Our power trading counterparties could also be adversely impacted by the market and economic conditions which could result in reduced wholesale power sales or increased counterparty credit risk. This is not intended to be an exhaustive list of possible effects, and we may be adversely impacted in other ways.

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

A significant percentage of our generating capacity, off-system sales margins, assets and operating expenses is attributable to Palo Verde. Our 15.8% interest in each of the three Palo Verde units totals approximately 633 MW of generating capacity. Palo Verde represents approximately 35% of our available net generating capacity and provided approximately 45% of our energy requirements for the twelve months ended December 31, 2011. Palo Verde comprises approximately 32% of our total net plant-in-service and Palo Verde expenses comprise a significant portion of operation and maintenance expenses. APS is the operating agent for Palo Verde, and we have limited ability under the ANPP Participation Agreement to influence operations and costs at Palo Verde. Palo Verde operated at a capacity factor of 90.7% and 90.4% in the twelve months ended December 31, 2011 and 2010, respectively.

Our ability to increase retail base rates in Texas and New Mexico is limited. We cannot assure that revenues will be sufficient to recover any increased costs, including any increased costs in connection with Palo Verde or other operations, whether as a result of inflation, changes in tax laws, regulatory requirements, or other causes.

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

In general, by law, we are entitled to recover our reasonable and necessary fuel and purchased power expenses from our customers in Texas and New Mexico. NMPRC Case No. 09-00171-UT provides for energy delivered to New Mexico customers from the deregulated Palo Verde Unit 3 to be recovered through fuel and purchased power costs based upon a previous purchased power contract with Credit Suisse Energy, LLC. Fuel and purchased power expenses in New Mexico and Texas are subject to reconciliation by the PUCT and the NMPRC. Prior to the completion of a reconciliation, we record fuel and purchased power costs such that fuel revenues equal recoverable fuel and purchased power expense including the repriced energy costs for Palo Verde Unit 3 in New Mexico. Our current rate filing at the PUCT (Docket No. 40094) includes a request to reconcile $356.6 million of fuel expense for the period July 1, 2009 through September 30, 2011. In the event that recovery of fuel and purchased power expenses is denied in a reconciliation proceeding, the amounts recorded for fuel and purchased power expenses could differ from the amounts we are allowed to collect from our customers, and we would incur a loss to the extent of the disallowance.

In New Mexico, the FPPCAC allows us to reflect current fuel and purchased power expenses in the FPPCAC and to adjust for under-recoveries and over-recoveries with a two-month lag. In Texas, fuel costs are recovered through a fixed fuel factor. In Texas, we can seek to revise our fixed fuel factor based upon our approved formula at least four months after our last revision except in the month of December. If we materially under-recover fuel costs, we may seek a surcharge to recover those costs at any time the balance exceeds a threshold material amount and is expected to continue to be materially under-recovered. During periods of significant increases in natural gas prices, the Company realizes a lag in the ability to reflect increases in fuel costs in its fuel recovery mechanisms in Texas. As a result, cash flow is impacted due to the lag in payment of fuel costs and collection of fuel costs from customers. To the extent the fuel and purchased power recovery processes in Texas and New Mexico do not provide for the timely recovery of such costs, we could experience a material negative impact on our cash flow. At December 31, 2011 and 2010, the Company had a net under-collection balance of $7.0 million and a net over-collection balance of $19.0 million, respectively.

Equipment Failures and Other External Factors Can Adversely Affect Our Results

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

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

As a result of changes in federal law, our wholesale and large retail customers already have, in varying degrees, alternative sources of power, including co-generation of electric power. Deregulation legislation is in effect in Texas requiring us to separate our transmission and distribution functions, which would remain regulated, from our power generation and energy services businesses, which would operate in a competitive market, in the future. In 2004, the PUCT approved a rule delaying retail competition in our Texas service territory. This rule was codified in the Public Utility Regulatory Act ("PURA") in June 2011. PURA identifies various milestones that we must reach before retail competition can begin. The first milestone calls for the development, approval by the FERC, and commencement of independent operation of a regional transmission organization in the area that includes our service territory. This and other milestones are not likely to be achieved for a number of years, if they are achieved at all. There is substantial uncertainty about both the regulatory framework and market conditions that would exist if and when retail competition is implemented in our Texas service territory, and we may incur substantial preparatory, restructuring and other costs that may not ultimately be recoverable. There can be no assurance that deregulation would not adversely affect our future operations, cash flow and financial condition.

Future Costs of Compliance with Environmental Laws and Regulations Could
Adversely Affect Our Operations and Consolidated Financial Results

We are subject to extensive federal, state and local environmental statutes, rules and regulations relating to discharges into the air, air quality, discharges of effluents into water, water quality, the use of water, the handling, disposal and clean-up of hazardous and non-hazardous substances and wastes, natural resources, and health and safety. Compliance with these legal requirements, which change frequently and often become more restrictive, could require us to commit significant capital and operating resources toward permitting, emission fees, environmental monitoring, installation and operation of air quality control equipment and purchases of air emission allowances and/or offsets. Costs of compliance with environmental laws and regulations or fines or penalties resulting from non-compliance, if not recovered in our rates, could adversely affect our operations and/or consolidated financial results, especially if emission and/or discharge limits are tightened, more extensive permitting requirements are imposed, additional substances become regulated and the number and types of assets we operate increases. We cannot estimate our compliance costs or any possible fines or penalties with certainty, or the degree to which such costs might be recovered in our rates, due to our inability to predict the requirements and timing of implementation of environmental rules or regulations. For example, the EPA has issued in the recent past various final and proposed regulations regarding air emissions from our operations as well as the rest of the utility sector, including the CSAPR and the Utility MACT. If these regulations survive legal and Congressional challenges, the cost to us to comply could adversely affect our operations and consolidated financial results.

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

The Company emits GHGs through the operation of its power plants. Federal legislation had been introduced in both houses of Congress to regulate the emission of GHGs and numerous states have adopted programs to stabilize or reduce GHG emissions. Additionally, the EPA is proceeding with regulation of GHG under the CAA. Under EPA regulations finalized in May 2010, the EPA began regulating GHG emissions from certain stationary sources, such as power plants, in January 2011. In 2012, EPA plans to publish draft rules to regulate GHG from new or modified power plants. Further, state regulation may precede federal GHG legislation. In the State of New Mexico, where we operate one facility and have an interest in another facility, the New Mexico Environmental Improvement Board approved two separate rulemakings in November and December 2010 to limit GHG emissions. To date, one of these rulemakings has been repealed by the New Mexico Environmental Improvement Board. There are various uncertainties relating to the remaining regulation, including whether current legal challenges to it will be successful, but as drafted, we do not expect this regulation to result in significant costs to us.

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

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Item 1B. Unresolved Staff Comments
None.

Executive Officers of the Registrant
The executive officers of the Company are elected annually and serve at the discretion of the Board of Directors. The executive officers of the Company as of February 24, 2012, were as follows:

Name	Age	Current Position and Business Experience
Thomas V. Shockley III	66	Interim Chief Executive Officer since January 2012; Vice – Chairman and Chief Operating Officer for American Electric Power from June 2000 to August 2004; retired in 2004.
David W. Stevens *	52	Chief Executive Officer since November 2008; Principal of Professional Consulting Services, LLC from December 2007 to November 2008; President, Chief Executive Officer and Board Member for Cascade Natural Gas Corporation from April 2005 to July 2007.
David G. Carpenter	56	Senior Vice President and Chief Financial Officer since August 2009; Vice President – Regulatory Services and Controller from September 2008 to August 2009; Vice President – Corporate Planning and Controller from August 2005 to September 2008.
Richard G. Fleager	61	Senior Vice President – Customer Care and External Affairs since April 2009; Vice President for Texas Gas Service from September 1997 to March 2009.
Mary E. Kipp	44	Senior Vice President, General Counsel and Chief Compliance Officer since June 2010; Vice President – Legal and Chief Compliance Officer from December 2009 to June 2010; Assistant General Counsel and Director of FERC Compliance from December 2007 to December 2009; Senior Enforcement Attorney – FERC from January 2004 to December 2007.
Rocky R. Miracle	58	Senior Vice President – Corporate Planning and Development since August 2009; Vice President – Corporate Planning from September 2008 to August 2009; Director of Business Operations Support – Texas Operations for American Electric Power Services Corporation from August 2004 to August 2008.
Hector R. Puente	55	Senior Vice President – Operations since May 2011; Vice President – Transmission and Distribution from May 2006 to May 2011.
Steven T. Buraczyk	44	Vice President – System Operations and Planning since January 2011; Vice President – Power Marketing and Fuels from July 2008 to January 2011; Director of Power Marketing and Fuels from August 2006 to July 2008.
Steven P. Busser	43	Vice President – Treasurer since January 2011; Vice President – Treasurer and Chief Risk Officer from May 2006 to January 2011.
Robert C. Doyle	52	Vice President – Transmission and Distribution since June 2011; Vice President – New Mexico Affairs from February 2007 to June 2011; Director – New Mexico Affairs from January 2007 to February 2007.
Nathan T. Hirschi	48	Vice President and Controller since March 2010; Vice President – Special Projects from December 2009 to February 2010; Partner for KPMG LLP from October 2003 to April 2009.
Kerry B. Lore	52	Vice President – Customer Care since December 2008; Vice President – Administration from May 2003 to December 2008.

Andres R. Ramirez	51	Vice President – Power Generation since February 2006.
Guillermo Silva, Jr.	58	Corporate Secretary since February 2006.
John A. Whitacre	62	Vice President – Power Marketing and Fuels since January 2011; Vice President – System Operations and Planning from May 2006 to January 2011.

* On January 30, 2012, Mr. Stevens resigned from his position as Chief Executive Officer of the Company, effective March 2, 2012, and as a Director immediately. The Board of Directors appointed Mr. Shockley to serve as interim Chief Executive Officer initially during a transition period until Mr. Stevens' departure and thereafter while a search is conducted to replace Mr. Stevens.

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Item 2. Properties

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

The Company owns an executive and administrative office building in El Paso. The Company leases land in El Paso adjacent to the Newman Power Station under a lease which expires in June 2033 with a renewal option of 25 years. The Company also leases certain warehouse facilities in El Paso under a lease which expires in December 2014. The Company has several other leases for office and parking facilities which expire within the next five years.

Item 3. Legal Proceedings

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

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

Item 4. Removed and Reserved

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PART II

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

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

	Sales Price High	Low	Close (End of period)	Dividends
2010				
First Quarter	$20.98	$18.74	$20.60	$—
Second Quarter	22.15	18.76	19.35	—
Third Quarter	23.82	18.81	23.78	—
Fourth Quarter	28.65	23.51	27.53	—
2011				
First Quarter	$30.68	$26.65	$30.40	$—
Second Quarter	32.40	29.09	32.30	0.22
Third Quarter	35.65	29.82	32.09	0.22
Fourth Quarter	35.71	30.29	34.64	0.22

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Performance Graph

The following graph compares the performance of the Company’s Common Stock to the performance of the NYSE Composite, and the Edison Electric Institute’s Index of investor-owned electric utilities setting the value of each at December 31, 2006 to a base of 100. The table sets forth the relative yearly percentage change in the Company’s cumulative total shareholder return as compared to the NYSE, and the EEI, as reflected in the graph.

	12/31/2006	12/31/2007	12/31/2008	12/31/2009	12/31/2010	12/31/2011
EE	100	105	74	83	113	142
EEI	100	117	86	96	102	123
NYSE US	100	107	63	79	87	82

As of January 31, 2012, there were 3,335 holders of record of the Company’s common stock. The Company has been paying quarterly dividends on its common stock since June 30, 2011 and paid a total of $27.2 million in cash dividends during the twelve months ended December 31, 2011. On January 26, 2012, our Board of Directors declared a quarterly cash dividend of $0.22 per share payable on March 30, 2012 to shareholders of record on March 15, 2012. At the current payout rate, we would expect to pay total cash dividends of approximately $35.2 million during 2012. The Board of Directors plans to review the Company's dividend policy annually, in conjunction with the annual shareholders meeting held in the second quarter of each year. 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. Since 1999, the Company has returned cash to stockholders through a stock repurchase program pursuant to which the Company has bought approximately 25.4 million shares at an aggregate cost of $423.6 million, including commissions. Under the Company’s program, purchases can be made at open market prices or in private transactions and repurchased shares are available for issuance under employee benefit and stock incentive plans, or may be retired. On March 21, 2011, the Board of Directors authorized a repurchase of up to 2.5 million shares of the Company’s outstanding common stock (the “2011 Plan”). During the twelve months ended December 31, 2011, the Company repurchased 2,782,455 shares of common stock in the open market at an aggregate cost of $86.5 million under both a previously authorized program and under the 2011 Plan. As of December 31, 2011, 393,816 shares remain eligible for repurchase under the 2011 Plan. During the fourth quarter of 2011, the Company repurchased 280,389 shares at an aggregate cost of $9.2 million. The table below provides the amount of the fourth quarter repurchases on a monthly basis.

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Period	Total Number of Shares Purchased	Average Price Paid per Share (Including Commissions)	Total Number of Shares Purchased as Part of a Publicly Announced Program	Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs
October 1 to October 31, 2011	—	$—	—	674,205
November 1 to November 30, 2011	162,435	32.86	162,435	511,770
December 1 to December 31, 2011	117,954	33.03	117,954	393,816

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

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Item 6. Selected Financial Data

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

	Years Ended December 31,				
	2011	2010	2009	2008	2007
Operating revenues	$918,013	$877,251	$827,996	$1,038,930	$877,427
Operating income	$190,803	$168,962	$133,165	$145,736	$128,321
Income before extraordinary items	$103,539	$90,317	$66,933	$77,621	$74,753
Extraordinary gain, net of tax (a)	$—	$10,286	$—	$—	$—
Net income	$103,539	$100,603	$66,933	$77,621	$74,753
Basic earnings per share:					
Income before extraordinary items	$2.49	$2.08	$1.50	$1.73	$1.64
Extraordinary gain (a)	$—	$0.24	$—	$—	$—
Net income	$2.49	$2.32	$1.50	$1.73	$1.64
Weighted average number of shares outstanding	41,349,883	43,129,735	44,524,146	44,777,765	45,563,858
Diluted earnings per share:					
Income before extraordinary items	$2.48	$2.07	$1.50	$1.72	$1.63
Extraordinary gain (a)	$—	$0.24	$—	$—	$—
Net income	$2.48	$2.31	$1.50	$1.72	$1.63
Weighted average number of shares and dilutive potential shares outstanding	41,587,059	43,294,419	44,595,067	44,930,109	45,873,018
Dividends declared per share of common stock	$0.66	$—	$—	$—	$—
Cash additions to utility property, plant and equipment	$178,041	$169,966	$209,974	$198,711	$144,588
Total assets	$2,396,851	$2,364,766	$2,226,152	$2,069,083	$1,853,888
Long-term debt and financing obligations, net of current portion	$816,497	$849,745	$804,975	$809,718	$655,111
Common stock equity	$760,251	$810,375	$722,729	$694,229	$666,459

(a) Extraordinary gain for 2010 includes a $10.3 million extraordinary gain or $0.24 earnings per share related to Texas regulatory assets.

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

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

Summary of Critical Accounting Policies and Estimates

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

Regulatory Accounting

We apply accounting standards that recognize the economic effects of rate regulation in our Texas, New Mexico and FERC jurisdictions. As a result, we record certain costs or obligations as either assets or liabilities on our balance sheet and amortize them in subsequent periods as they are reflected in regulated rates. The deferral of costs as regulatory assets is appropriate only when the future recovery of such costs is probable. In assessing probability, we consider such factors as specific regulatory orders, regulatory precedent and the current regulatory environment. As of December 31, 2011, we had recorded regulatory assets currently subject to recovery in future rates of approximately $101.0 million and regulatory liabilities of approximately $21.0 million as discussed in greater detail in Note D of the Notes to the Consolidated Financial Statements. In the event we determine that we can no longer apply the FASB guidance for regulated operations to all or a portion of our operations or to the individual regulatory assets recorded, we could be required to record a charge against income in the amount of the remaining unamortized net regulatory assets. Such an action could materially reduce our shareholders’ equity.

Collection of Fuel Expense

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

Decommissioning Costs and Estimated Asset Retirement Obligation

Pursuant to the ANPP Participation Agreement and federal law, we must fund our share of the estimated costs to decommission Palo Verde Units 1, 2 and 3 and associated common areas. The determination of the estimated liability requires the use of various assumptions pertaining to decommissioning costs, escalation and discount rates. We determine how we will fund our share of those estimated costs by making assumptions about future investment returns and future decommissioning cost escalations. Decommissioning costs will be adjusted prospectively for future changes in estimated decommissioning costs and when actual costs are incurred to decommission the plant. If the rates of return earned by the trusts fail to meet expectations or if estimated costs to decommission the plant increase, we could be required to increase our funding to the decommissioning trust accounts. Historically, we have been permitted to collect in rates in Texas and New Mexico the costs of nuclear decommissioning.

Future Pension and Other Postretirement Obligations

Our obligations to retirees under various benefit plans are recorded as a liability on the consolidated balance sheets. Our liability is calculated on the basis of significant assumptions regarding discount rates, expected return on plan assets, rate of compensation increase, life expectancy of retirees and health care cost inflation. Changes in these assumptions could have a material impact on both net income and on the amount of liabilities reflected on the consolidated balance sheets.

Tax Accruals

We use the asset and liability method of accounting for income taxes. Under this method, we recognize deferred tax assets and liabilities for the future tax consequences attributable to temporary differences between the financial statement carrying

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amounts and the tax basis of existing assets and liabilities. The application of income tax law and regulations is complex and we must make judgments regarding income tax exposures. Changes in these judgments, due to changes in law, regulation, interpretation, or audit adjustments can materially affect amounts we recognize in our consolidated financial statements.

Overview

The following is an overview of our results of operations for the years ended December 31, 2011, 2010 and 2009. Income before extraordinary item for the years ended December 31, 2011, 2010 and 2009 is shown below:

	Years Ended December 31,		
	2011	2010	2009
Income before extraordinary item (in thousands)	$103,539	$90,317	$66,933
Basic earnings per share before extraordinary item	2.49	2.08	1.50

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The following table and accompanying explanations show the primary factors affecting the after-tax change in income before extraordinary item between the calendar years ended 2011 and 2010, 2010 and 2009, and 2009 and 2008 (in thousands):

	2011		2010		2009	
Prior year December 31 income before extraordinary item	$90,317		$66,933		$77,621	
Change in (net of tax):						
Increased retail non-fuel base revenues	21,198	(a)	33,395	(b)	8,292	(c)
Elimination of Medicare Part D tax benefit	4,787	(d)	(4,787	) (d)	—	
Increased transmission wheeling revenue	3,197	(e)	1,446		1,887	
Decreased (increased) Palo Verde operations and maintenance expense	640		2,753	(f)	(2,266	) (g)
Decreased (increased) operations and maintenance at fossil fuel generating plants	(3,725	) (h)	(1,120	)	517	
Increased (decreased) off-system sales margins retained	(3,935	) (i)	(3,224	) (j)	(7,140	) (k)
Decreased (increased) customer care expense	(2,069	) (l)	(2,445	) (m)	(483	)
Increased interest on long-term debt (net of capitalized interest)	(377	)	775		(3,518	) (n)
Increased (decreased) AFUDC	(3,804	) (o)	1,909	(p)	2,327	(p)
Decreased (increased) transmission and distribution operations and maintenance expense	(1,964	) (q)	1,200		378	
Decreased (increased) administrative and general expense	(1,342	)	(3,502	) (r)	(2,544	) (s)
Increased taxes other than income taxes	(678	)	(2,830	) (t)	(121	)
Increased (decreased) deregulated Palo Verde Unit 3 revenues	(808	)	1,235		(7,121	) (u)
Decreased (increased) depreciation and amortization	(202	)	(3,821	) (v)	393	
Other	2,304		2,400		(1,289	)
Current year December 31 income before extraordinary item	$103,539		$90,317		$66,933	

(a) Retail non-fuel base revenues increased in 2011 compared to 2010 primarily due to a 3.1% increase in kWh sales to retail customers reflecting hotter summer weather with higher non-fuel base summer rates and1.4% growth in the average number of retail customers served in 2011. Retail non-fuel base revenues exclude fuel recovered through New Mexico base rates.

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

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

(d) A one-time charge to income tax expense was incurred in 2010 to recognize a change in tax law enacted in the Patient Protection and Affordable Care Act to eliminate the tax benefit related to the Medicare Part D subsidies with no comparable tax expense in 2011.

(e) Transmission revenues increased in 2011 primarily due to a settlement agreement with Tucson Electric Power Company resolving a transmission dispute that resulted in a one-time adjustment to income of $3.9 million, pre-tax and annual revenue of $1.1 million per year.

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

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

(h)

Operations and maintenance at gas-fired fuel generating stations increased largely as a result of weather-related damage during severe winter weather in February 2011 and freeze protection upgrades.

(i) Off-system sales margins decreased in 2011 compared to 2010 primarily due to lower average market prices for power and an increase in sharing of off-system sales margins with customers from 25% to 90% effective in July 2010.

(j) Off-system sales margins decreased in 2010 compared to 2009 due to increased sharing of off-system sales margins with customers from 25% to 90% effective July 1, 2010 consistent with prior rate agreements in Texas and New Mexico.

(k) Lower retained margins on off-system sales in 2009 compared to 2008 are primarily the result of reduced margins per MWh due to lower market prices and a decline in MWh sales.

(l) Customer care expense increased in 2011 compared to 2010 primarily due to increased costs for customer-related activities, an increase in uncollectible customer accounts, and an increase in payroll costs.

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(m) Customer care expense increased in 2010 compared to 2009 primarily due to the transition to our new customer billing system and increased uncollectible customer accounts.

(n) Interest expense on long-term debt increased for 2009 compared to 2008 due to the issuance of $150 million of 7.5% Senior Notes in June 2008 and higher interest rates on auction rate pollution control bonds in 2008.

(o) AFUDC (allowance for funds used during construction) decreased in 2011 compared to 2010 primarily due to lower balances of construction work in progress subject to AFUDC.

(p) AFUDC increased primarily due to higher balances of construction work in progress subject to AFUDC.

(q) Transmission and distribution operations and maintenance expense increased in 2011 compared to 2010 primarily due to increased wheeling expense, a reliability study for the North American Electric Reliability Corporation, and an increase in payroll costs.

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

(s) Administrative and general expenses increased in 2009 compared to 2008 primarily due to increased accruals for employee incentive compensation and increased pension and benefits expenses reflecting a lower discount rate used to determine postretirement benefit costs.

(t) Taxes other than income taxes increased in 2010 compared to 2009 due to revenue-related taxes and increased property taxes.

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

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

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Historical Results of Operations

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

Operating revenues

We realize revenue from the sale of electricity to retail customers at regulated rates and the sale of energy in the wholesale power market generally at market-based prices. Sales for resale (which are wholesale sales within our service territory) accounted for less than 1% of revenues. Off-system sales are wholesale sales into markets outside our service territory. Off-system sales are primarily made in off-peak periods when we have competitive generation capacity available after meeting our regulated service obligations. We shared 25% of off-system sales margins with our Texas and New Mexico customers and retained 75% of off-system sales margins through June 30, 2010. Pursuant to rate agreements in prior years, effective July 1, 2010, we share 90% of off-system sales margins with our Texas and New Mexico customers, and we retain 10% of off-system sales margins. We are sharing 25% of our off-system sales margins with our sales for resale customer under the terms of a contract which was effective April 1, 2008.

Revenues from the sale of electricity include fuel costs that are recovered from our customers through fuel adjustment mechanisms. A significant portion of fuel costs are also recovered through base rates in New Mexico. We record deferred fuel revenues for the difference between actual fuel costs and recoverable fuel revenues until such amounts are collected from or refunded to customers. “Non-fuel base revenues” refers to our revenues from the sale of electricity excluding such fuel costs.

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

	Twelve Months Ended December 31,					
	2011		2010		2009	
Residential	41	%	41	%	41	%
Commercial and industrial, small	34		35		36	
Commercial and industrial, large	8		8		7	
Sales to public authorities	17		16		16	
Total retail non-fuel base revenues	100	%	100	%	100	%

No retail customer accounted for more than 4% of our non-fuel 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 reflects higher base rates during the peak summer season of May through October and lower base rates during November through April for our residential and small commercial and industrial customers. As a result, our business is seasonal, with higher kWh sales and revenues during the summer cooling season. The following table sets forth the percentage of our retail non-fuel base revenues derived during each quarter for the periods presented:

	Years Ended December 31,					
	2011		2010		2009	
January 1 to March 31	18	%	21	%	21	%
April 1 to June 30	27		24		26	
July 1 to September 30	34		33		30	
October 1 to December 31	21		22		23	
Total	100	%	100	%	100	%

Weather significantly impacts our residential, small commercial and industrial customers, and to a lesser extent, our sales to public authorities. 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 for 2011, 2010 and 2009.

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	2011	2010	2009	30-year Average
Heating degree days	2,402	2,273	2,144	2,426
Cooling degree days	3,135	2,738	2,768	2,410

Customer growth is a key driver in the growth of retail sales. The average number of retail customers grew 1.4% in 2011 and 1.7% in 2010. See the tables presented on pages 35 and 36 which provide detail on the average number of retail customers and the related revenues and kWh sales.

Retail non-fuel base revenues. The 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. As a result, our revenues are more seasonal than prior to July 2010.

Retail non-fuel base revenues increased by $33.6 million, or 6.3% for the twelve months ended December 31, 2011 when compared to the same period in 2010. The increase was primarily due to a 3.1% increase in kWh sales to retail customers, reflecting hotter summer weather with higher non-fuel base summer rates, and 1.4% growth in the average number of retail customers served. During the twelve months ended December 31, 2011, cooling degree days were 14% above the same period in 2010 and 30% above the 30-year average. KWh sales to residential customers and small commercial and industrial customers increased 5.0% and 2.5%, respectively, during the twelve months ended December 31, 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.

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

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 our approved formula at least four months after our last revision except in the month of December. In addition, if we materially over-recover fuel costs, we must seek to refund the over-recovery, and if we materially under-recover fuel costs, we may seek a surcharge to recover those costs. Fuel over and under recoveries are considered material when they exceed 4% of the previous twelve months' fuel costs.

We under-recovered fuel costs by $13.9 million in the twelve months ended December 31, 2011. In the twelve months ended December 31, 2010 and 2009, we over-recovered fuel costs by $35.4 million and $66.6 million, respectively. Refunds of $12.0 million and $34.8 million were returned to our Texas customers in the twelve months ended December 31, 2011 and 2010, respectively. Refunds net of surcharges of $0.5 million were returned to our Texas customers in the twelve months ended December 31, 2009. At December 31, 2011, we had a fuel under-recovery balance of $7.0 million, including an under-recovery balance of $9.1 million in Texas partially offset by an over-recovery balance of $2.1 million in New Mexico. Over-recoveries in New Mexico will be refunded through our fuel adjustment clause during 2012.

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. We 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.

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The table below shows MWhs, sales revenue, fuel costs, total margins, and retained margins made on off-system sales for the twelve months ended December 31, 2011, 2010 and 2009 (in thousands except for MWhs).

	Twelve Months Ended December 31,		
	2011	2010	2009
MWh sales	2,687,631	2,822,732	2,995,984
Sales revenues	$78,059	$105,317	$116,064
Fuel cost	$74,736	$93,516	$101,665
Total margins	$3,323	$11,801	$14,399
Retained margins	$(560)	$5,687	$10,803

Off-system sales revenues decreased $27.3 million, or 25.9% for the twelve months ended December 31, 2011 when compared to 2010 as a result of lower average market prices for power and a 4.8% decline in MWh sales. For the twelve months ended December 31, 2011, retained margins decreased $6.2 million when compared to the same period in 2010. Off-system margins were negatively affected by lower costs of natural gas which impact the average market prices in the wholesale power markets. Off-system sales margins were also negatively impacted by power purchases required for system reliability during extremely cold weather in February 2011. Off-system sales revenues decreased $10.7 million or 9.3% for the twelve months ended December 31, 2010 when compared to 2009 as a result of lower average market prices for power and a 5.8% decline in MWh sales. For the twelve months ended December 31, 2010, retained margins decreased $5.1 million or 47.4% when compared to the same period in 2009. Customers were credited with 25% of the off-system sales margins through fuel recovery mechanisms through June 30, 2010. In July 2010, off-system sales margins shared with customers in Texas and New Mexico increased to 90%.

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

			Increase (Decrease)		
Years Ended December 31:	2011	2010	Amount	Percent	
kWh sales:					
Retail:					
Residential	2,633,390	2,508,834	124,556	5.0 %	
Commercial and industrial, small	2,352,218	2,295,537	56,681	2.5	
Commercial and industrial, large	1,096,040	1,087,413	8,627	0.8	
Sales to public authorities	1,579,565	1,542,389	37,176	2.4	
Total retail sales	7,661,213	7,434,173	227,040	3.1	
Wholesale:					
Sales for resale	62,656	53,637	9,019	16.8	
Off-system sales	2,687,631	2,822,732	(135,101)	(4.8)	
Total wholesale sales	2,750,287	2,876,369	(126,082)	(4.4)	
Total kWh sales	10,411,500	10,310,542	100,958	1.0	
Operating revenues:					
Non-fuel base revenues:					
Retail:					
Residential	$234,086	$217,615	$16,471	7.6 %	
Commercial and industrial, small	196,093	188,390	7,703	4.1	
Commercial and industrial, large	45,407	43,844	1,563	3.6	
Sales to public authorities	94,370	86,460	7,910	9.1	
Total retail non-fuel base revenues	569,956	536,309	33,647	6.3	
Wholesale:					
Sales for resale	2,122	1,943	179	9.2	
Total non-fuel base revenues	572,078	538,252	33,826	6.3	
Fuel revenues:					
Recovered from customers during the period	145,130	170,588	(25,458)	(14.9)	(1)
Under (over) collection of fuel	13,917	(35,408)	49,325	N/A	
New Mexico fuel in base rates	73,454	71,876	1,578	2.2	
Total fuel revenues	232,501	207,056	25,445	12.3	(2)
Off-system sales:					
Fuel cost	74,736	93,516	(18,780)	(20.1)	
Shared margins	3,883	6,114	(2,231)	(36.5)	
Retained margins	(560)	5,687	(6,247)	N/A	
Total off-system sales	78,059	105,317	(27,258)	(25.9)	
Other	35,375	26,626	8,749	32.9	(3)
Total operating revenues	$918,013	$877,251	$40,762	4.6	
Average number of retail customers:					
Residential	336,219	331,869	4,350	1.3	
Commercial and industrial, small	37,652	36,536	1,116	3.1	
Commercial and industrial, large	50	49	1	2.0	
Sales to public authorities	4,626	4,701	(75)	(1.6)	
Total	378,547	373,155	5,392	1.4	

(1) Excludes $12.0 million and $34.8 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 $14.8 million and $16.1 million, respectively.

(3) Represents revenues with no related kWh sales. 2011 includes a one-time $3.9 million settlement of a transmission dispute with Tucson Electric Power Company.

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Years Ended December 31:	2010	2009	Increase (Decrease) Amount	Percent	
kWh sales:					
Retail:					
Residential	2,508,834	2,361,650	147,184	6.2 %	
Commercial and industrial, small	2,295,537	2,251,399	44,138	2.0	
Commercial and industrial, large	1,087,413	1,024,186	63,227	6.2	
Sales to public authorities	1,542,389	1,482,448	59,941	4.0	
Total retail sales	7,434,173	7,119,683	314,490	4.4	
Wholesale:					
Sales for resale	53,637	56,931	(3,294)	(5.8)	
Off-system sales	2,822,732	2,995,984	(173,252)	(5.8)	
Total wholesale sales	2,876,369	3,052,915	(176,546)	(5.8)	
Total kWh sales	10,310,542	10,172,598	137,944	1.4	
Operating revenues:					
Non-fuel base revenues:					
Retail:					
Residential	$217,615	$195,798	$21,817	11.1 %	
Commercial and industrial, small	188,390	175,328	13,062	7.5	
Commercial and industrial, large	43,844	34,804	9,040	26.0	
Sales to public authorities	86,460	77,370	9,090	11.7	
Total retail non-fuel base revenues	536,309	483,300	53,009	11.0	
Wholesale:					
Sales for resale	1,943	2,037	(94)	(4.6)	
Total non-fuel base revenues	538,252	485,337	52,915	10.9	
Fuel revenues:					
Recovered from customers during the period	170,588	196,081	(25,493)	(13.0)	(1)
Under (over) collection of fuel	(35,408)	(66,608)	31,200	(46.8)	
New Mexico fuel in base rates	71,876	69,026	2,850	4.1	
Total fuel revenues	207,056	198,499	8,557	4.3	(2)
Off-system sales:					
Fuel cost	93,516	101,665	(8,149)	(8.0)	
Shared margins	6,114	3,596	2,518	70.0	
Retained margins	5,687	10,803	(5,116)	(47.4)	
Total off-system sales	105,317	116,064	(10,747)	(9.3)	
Other	26,626	28,096	(1,470)	(5.2)	(3)
Total operating revenues	$877,251	$827,996	$49,255	5.9	
Average number of retail customers:					
Residential	331,869	326,002	5,867	1.8	
Commercial and industrial, small	36,536	36,040	496	1.4	
Commercial and industrial, large	49	49	—	—	
Sales to public authorities	4,701	4,940	(239)	(4.8)	
Total	373,155	367,031	6,124	1.7	

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

(2) Includes deregulated Palo Verde Unit 3 revenues for the New Mexico jurisdiction of $16.1 million and $14.1 million, respectively.

(3) Represents revenues with no related kWh sales.

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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 55% of our Company-generated energy for the twelve months ended December 31, 2011. 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.

Average costs per MWh were flat while energy expenses increased $6.9 million or 2.4% for the twelve months ended December 31, 2011 due to increased energy requirements. Energy expenses in 2011, compared to 2010, increased primarily due to: (i) an increase of $10.7 million in natural gas costs due to a 16% increase in MWh generated with natural gas partially offset by a 6% decrease in the average price of natural gas; (ii) an increase of $8.7 million in the cost of nuclear fuel primarily due to a 14% increase in the cost of nuclear fuel consumed and a $3.3 million DOE settlement related to spent nuclear fuel received in 2010 with no comparable activity in 2011; and (iii) an increase of $4.3 million in coal expense 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 of $0.5 million in 2010, and a 12% increase in the cost of coal burned. These increases were partially offset by a $16.8 million decrease in purchased power cost due to a 13% decrease in MWhs purchased and a 6% decrease in the average price of purchased power. Total energy requirements increased 0.2 million MWhs in 2011 compared to 2010 due to increased retail sales.

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

The table below details the sources and costs of energy for 2011, 2010 and 2009.

	2011				2010			
Fuel Type	Cost		MWh	Cost per MWh	Cost		MWh	Cost per MWh
	(in thousands)				(in thousands)			
Natural Gas	$164,260	(a)	3,346,789	$50.02	$153,568		2,890,110	$53.14
Coal	15,273	(b)	647,932	19.97	11,011		650,236	17.79
Nuclear	43,974		4,942,055	8.90	35,250	(c)	4,925,313	7.82
Total	223,507		8,936,776	25.10	199,829		8,465,659	24.06
Purchased power	75,149		2,112,596	35.57	91,916		2,420,869	37.97
Total energy	$298,656		11,049,372	27.10	$291,745		10,886,528	27.15

	2009		
Fuel Type	Cost	MWh	Cost per MWh
	(in thousands)		
Natural Gas	$143,943	2,385,632	$60.34
Coal	12,838	744,858	17.24
Nuclear	29,056	4,848,800	5.99
Total	185,837	7,979,290	23.29
Purchased power	108,603	2,745,500	39.56
Total energy	$294,440	10,724,790	27.45

(a) Natural gas costs exclude $3.2 million of energy expenses capitalized related to Newman Unit 5 pre-commercial testing recorded in 2011.
(b) Coal costs include $2.3 million adjustment for final coal reclamation amortization in accordance with PUCT Docket No. 38361 recorded in 2011.
(c) Includes a DOE refund of $3.3 million recorded in 2010.

Other operations expense

Other operations expense increased $5.3 million or 2.4% in 2011 compared to 2010 primarily due to: (i) increased customer care expenses of $3.3 million related to increased costs for customer-related activities, an increase in uncollectible customer accounts, and an increase in payroll costs; and (ii) increased transmission operations expense of $2.5 million primarily due to increased wheeling expense and a reliability study for the North American Electric Reliability Corporation.

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

Maintenance expense

Maintenance expenses increased $5.3 million or 9.3% in 2011 compared to 2010 due to an increase in maintenance expense largely as a result of weather-related damage during severe winter weather in February 2011 and freeze protection upgrades at our fossil-fuel generating plants.

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

Depreciation and amortization expense

Depreciation and amortization expense increased $0.3 million or 0.4% in 2011 compared to 2010 primarily due to increases in depreciable plant balances including Phase II of Newman Unit 5 and increased depreciation rates, largely offset by a reduction in depreciation rates related to Palo Verde resulting from the approval of the license extension for Palo Verde by the NRC in April 2011. Depreciation and amortization expense increased $6.1 million or 8.1% in 2010 compared to 2009 primarily due to increased depreciable plant balances including the new customer information system, increased amortization of New Mexico rate case costs, and increased depreciation rates.

Taxes other than income taxes

Taxes other than income taxes increased $1.1 million or 2.0% in 2011 compared to 2010 primarily due to increased revenue-related taxes and increased property taxes in Texas. Taxes other than income taxes increased $4.5 million or 9.0% in 2010 compared to 2009 primarily due to increased revenue-related taxes and increased property taxes.

Other income (deductions)

Other income (deductions) decreased $2.8 million or 19.4% in 2011 compared to 2010 due to decreased allowance for equity funds used during construction ("AEFUDC") due to lower balances of construction work in progress in 2011. Also during 2011, we incurred net unrealized and realized losses on equity investments in our decommissioning trust of $1.4 million compared to $0.1 million in 2010. The losses on equity investments were offset by increased interest income.

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

Interest charges (credits)

Interest charges (credits) increased $3.2 million or 7.5% in 2011 compared to 2010 primarily due to: (i) decreased allowance for borrowed funds used during construction ("ABFUDC") as a result of lower balances of construction work in progress in 2011; and (ii) increased commitment fees on our revolving credit facility.

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

Income tax expense

Income tax expense, before extraordinary item, increased by $2.7 million or 5.3% in 2011 compared to 2010 primarily due to increased pre-tax income partially offset by the recognition of a one-time non-cash charge to tax expense related to the impact

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of the tax deduction for the Medicare Part D subsidies from the Patient Protection and Affordable Care Act (“PPACA”) in March 2010 with no comparable amount in 2011. Income tax expense, before extraordinary item, increased by $18.0 million or 54.4% in 2010 compared to 2009 primarily due to an increase in pre-tax income and a one-time non-cash charge to tax expense related to the PPACA. A provision of the law is that, beginning in 2013, the income tax deductions for the cost of providing certain prescription drug coverage will be reduced by the amount of the Medicare Part D subsidies received. The Company was required to recognize the impacts of the tax law change at the time of enactment and recorded a one-time non-cash charge to income tax expense of approximately $4.8 million in the first quarter of 2010.

Extraordinary Item

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

New accounting standards

In 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 would have been 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 could require additional disclosure on our statement of operations and related notes. In December 2011, the FASB issued new guidance to defer the effective date for amendments to the presentation of reclassification of items out of accumulated other comprehensive income. Deferring the effective date will allow the FASB time to redeliberate whether to present on the face of the financial statements the effects of reclassifications out of accumulated other comprehensive income on the components of net income and other comprehensive income for all periods presented. While the FASB is considering the operational concerns about the presentation requirements for reclassification adjustments and the needs of financial statement users for additional information about reclassification adjustments, we will continue to report reclassifications out of accumulated other comprehensive income consistent with the presentation requirements in effect before the guidance issued in June 2011 until further guidance becomes available.

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. This guidance requires additional disclosure on fair value measurements but did not impact our consolidated financial statements.

Inflation

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

Liquidity and Capital Resources

We continue to maintain a strong balance of common stock equity in our capital structure which supports our bond ratings, allowing us to obtain financing from the capital markets at a reasonable cost. At December 31, 2011, our capital structure, including common stock, long-term debt, current maturities of long-term debt, and short-term borrowings under the revolving credit facility, consisted of 46.3% common stock equity and 53.7% debt. At December 31, 2011, we had on hand $8.2 million in cash and cash equivalents.

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Our principal liquidity requirements in the near-term are expected to consist of capital expenditures to expand and support electric service obligations, expenditures for nuclear fuel inventory, interest payments on our indebtedness, and operating expenses including fuel costs, maintenance costs, dividends and taxes.

Capital Requirements. During the twelve months ended December 31, 2011, our capital requirements primarily consisted of expenditures for the construction and purchase of electric utility plant, the repurchase of common stock, purchases of nuclear fuel, and the 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. In total, we expended $235.2 million on Newman Unit 5, including $25.4 million in 2011. These amounts include AFUDC. Estimated construction expenditures for all capital projects for 2012 are approximately $242 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”. Cash capital expenditures for new electric plant were $178.0 million in the twelve months ended December 31, 2011 and $170.0 million in the twelve months ended December 31, 2010.

On December 30, 2011, we paid $8.8 million of quarterly dividends to shareholders. We paid a total of $27.2 million in cash dividends during the twelve months ended December 31, 2011. On January 26, 2012, our Board of Directors declared a quarterly cash dividend of $0.22 per share payable on March 30, 2012 to shareholders of record on March 15, 2012. At the current payout rate, we would expect to pay total cash dividends of approximately $35.2 million during 2012. The Board of Directors plans to review the Company's dividend policy annually, in conjunction with the annual shareholders meeting held in the second quarter of each year. 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. 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 25.4 million shares at an aggregate cost of $423.6 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 (“2011 Plan”). During the twelve months ended December 31, 2011, we repurchased 2,782,455 shares of common stock in the open market at an aggregate cost of $86.5 million. As of December 31, 2011, 393,816 shares remain eligible for purchase under the 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 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 and net operating loss carryforwards, tax payments are expected to be minimal in 2012.

We continually evaluate our funding requirements related to our retirement plans, other postretirement benefit plans, and decommissioning trust funds. We contributed $13.8 million and $8.5 million to our retirement plans during the twelve months ended December 31, 2011 and 2010, respectively. We expect our funding requirements to increase in 2012. We also contributed $2.2 million and $4.6 million to our other postretirement benefit plan during the twelve months ended December 31, 2011 and 2010, respectively. We contributed $8.3 million and $8.2 million to our decommissioning trust funds for 2011 and 2010, respectively. We are in compliance with the funding requirements of the federal government for our benefit plans and decommissioning trust. We will continue to review our funding for these plans in order to meet our future obligations.

Capital Resources. During the twelve months ended December 31, 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 and an increase in accounts payable, offset by the timing of collection of fuel revenues to recover actual fuel expenses in 2011 compared to 2010. During the twelve months ended December 31, 2011, the Company had an under-recovery of fuel costs, net of refunds, of $26.0 million as compared to an over-recovery, net of refunds, of $1.0 million during the twelve months ended December 31, 2010. At December 31, 2011, we had a net fuel under-recovery balance of $7.0 million, including an under-recovery balance of $9.1 million in Texas partially offset by an over-recovery balance of $2.1 million in New Mexico.

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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.

We filed a request with the PUCT, the City of El Paso and other Texas cities on February 1, 2012 for a \$26.3 million increase in rates charged to customers in Texas. The rate filing was made in response to a resolution adopted by the El Paso City Council requiring us to show cause why our base rates for customers in the El Paso city limits should not be reduced. The City has until August 4, 2012 to make a determination regarding our base rates in the City of El Paso. The rate filing used a historical test year ended September 30, 2011, adjusted for known and measurable items, and a return on equity of 10.6%. The filing at the PUCT also includes a request to reconcile \$356.5 million of fuel expense for the period July 1, 2009 through September 30, 2011.

On November 15, 2011, the El Paso City Council adopted a resolution which established current rates as temporary rates for our customers residing within the city limits of El Paso. Temporary rates will be effective from November 15, 2011 until a final determination is made by the PUCT on our rates in the rate proceeding initiated by the City's Show Cause Order. Upon a final determination by the PUCT, the PUCT may order a refund to customers of money collected in excess of the rate finally ordered, including interest, or shall authorize us to surcharge bills to recover the amount, including interest, by which the money collected under the temporary rates is less than the money that would have been collected under the rate finally ordered. The rates proposed by the Company in the Texas rate case included increases for some customer classes and decreases for other customer classes. As a result, consistent implementation of the proposed rates may require the PUCT to reflect the differences in temporary and final rates from November 15, 2011 for each affected class.

While cities in Texas have jurisdiction over rates in their city limits, the PUCT has appellate authority over city rates decisions on a “de novo” basis, therefore, the ultimate authority to set our Texas electric rates is vested in the PUCT. We cannot predict the outcome of this proceeding. If the filed rate case results 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 the February 1, 2012 rate filing, 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 RGRT. RGRT is the trust through which we finance our portion of nuclear fuel for Palo Verde and is consolidated in the Company's financial statements. In November 2011, we refinanced and extended our \$200 million revolving credit facility, which includes an option, subject to lenders' approval, to expand the size to \$300 million. The amended facility reduces our borrowing costs and extends the maturity from September 2014 to September 2016. The total amount borrowed for nuclear fuel by RGRT was \$123.4 million at December 31, 2011 of which \$13.4 million had been borrowed under the revolving credit facility and \$110 million was borrowed through senior notes. At December 31, 2010, the total amount borrowed for nuclear fuel by RGRT was \$114.7 million of which \$4.7 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. At December 31, 2011, \$20.0 million was outstanding under 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 anticipate issuing long-term debt in the capital markets to finance capital requirements. In October 2011, we received approval from the NMPRC and the FERC to incrementally issue up to $300 million of long-term debt as and when needed. 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.

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Contractual Obligations. Our contractual obligations as of December 31, 2011 are as follows (in thousands):

	Payments due by period				
	Total	2012	2013 and 2014	2015 and 2016	2017 and Beyond
Long-Term Debt (including interest):					
Senior notes (1)	$1,406,844	$35,250	$70,500	$70,500	$1,230,594
Pollution control bonds (2)	480,458	44,214	20,274	20,274	395,696
RGRT Senior notes (3)	144,129	5,054	10,107	24,350	104,618
Financing Obligations (including interest):					
Revolving credit facility (4)	33,893	33,893	—	—	—
Purchase Obligations:					
Power contracts	5,730	3,042	2,688	—	—
Fuel contracts:					
Coal (5)	45,623	10,111	20,221	15,291	—
Gas (5)	281,054	41,465	62,898	64,556	112,135
Nuclear fuel (6)	139,505	30,542	29,324	31,310	48,329
Retirement Plans and Other Postretirement benefits (7)	18,344	18,344	—	—	—
Decommissioning trust funds (8)	163,016	4,636	9,272	9,272	139,836
Operating leases (9)	11,575	1,030	1,870	915	7,760
Total	$2,730,171	$227,581	$227,154	$236,468	$2,038,968

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

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

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

(4) This reflects obligations outstanding under the $200 million RCF used for, among other things, working capital and general corporate purposes. At December 31, 2011, $20 million was outstanding under this facility for working capital and general corporate purposes. Amounts borrowed by RGRT may be used, among other things, to finance nuclear fuel. At December 31, 2011, $13.4 million was borrowed for nuclear fuel. The balance includes interest based on actual interest rates at the end of 2011.

(5) Amount is based on the minimum volumes per the contract and market and/or contract price at the end of 2011. Gas obligation includes a gas storage contract and a gas transportation contract.

(6) Some of the nuclear fuel contracts are based on a fixed price, adjusted for a market index. The index used here is the index at the end of 2011.

(7) These obligations include our minimum contractual funding requirements for the non-qualified retirement income plan and the other postretirement benefits for 2012. We have a minimum funding requirement of $14 million related to our retirement income plan for 2012. However, we may decide to fund at higher levels and expect to contribute $19.8 million and $2.5 million to our retirement plans and postretirement benefit plan, respectively, in 2012, as disclosed in Part II, Item 8, Notes to Consolidated Financial Statements, Note M, Employee Benefits. Minimum funding requirements for 2012 and beyond are not included due to the uncertainty of interest rates and

the related return on assets.

(8) These obligations represent funding estimates based on amounts requested in PUCT Docket No. 40094 which was filed February 1, 2012. Decommissioning trust funding could be adjusted based on the final outcome of this case.

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

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Off-Balance Sheet Arrangements

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

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

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

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

Interest Rate Risk

Our long-term debt obligations are all fixed-rate obligations, except for our revolving credit facility which is based on floating rates.

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

Our decommissioning trust funds consist of equity securities and fixed income instruments and are carried at fair value. We face interest rate risk on the fixed income instruments, which consist primarily of municipal, federal and corporate bonds and which were valued at $89.3 million and $82.9 million as of December 31, 2011 and 2010, respectively. A hypothetical 10% increase in interest rates would reduce the fair values of these funds by $0.8 million and $1.2 million based on their fair values at December 31, 2011 and 2010, respectively.

Equity Price Risk

Our decommissioning trust funds include marketable equity securities of approximately $74.9 million and $68.0 million at December 31, 2011 and 2010, respectively. A hypothetical 20% decrease in equity prices would reduce the fair values of these funds by $15.0 million and $13.6 million based on their fair values at December 31, 2011 and 2010, respectively. Declines in market prices could require that additional amounts be contributed to our decommissioning trusts to maintain minimum funding requirements. We will not have a requirement to expend monies held in trust before 2044 or a later period when we begin to decommission Palo Verde.

Commodity Price Risk

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

In the normal course of business, we enter into contracts of various durations for the forward sales and purchases of electricity to effectively manage our available generating capacity and supply needs. Such contracts include forward contracts for the sale of generating capacity and energy during periods when our available power resources are expected to exceed the requirements of our retail native load and sales for resale. We also enter into forward contracts for the purchase of wholesale capacity and energy during periods when the market price of electricity is below our expected incremental power production costs or to supplement our generating capacity when demand is anticipated to exceed such capacity. As of January 31, 2012, we had entered into forward sales and purchase contracts for energy as discussed in Part I, Item 1, “Business – Energy Sources – Purchased Power” and “Regulation – Power Sales Contracts.” These agreements are generally fixed-priced contracts which qualify for the “normal purchases and normal sales” exception provided in FASB guidance for accounting for derivative instruments and hedging activities and are not recorded at their fair value in our financial statements. Because of the operation of the PUCT and NMPRC rules and our fuel clauses, these contracts do not expose us to significant commodity price risk.

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Management Report on Internal Control Over Financial Reporting

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

- Pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of the assets of the Company;
- Provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and the receipts and expenditures of the Company are being made only in accordance with authorizations of management and directors of the Company; and
- Provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company's assets that could have a material effect on the financial statements.

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

The Company's management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2011. In making this assessment, the Company's management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in Internal Control-Integrated Framework. Based on its assessment, management believes that, as of December 31, 2011, the Company's internal control over financial reporting is effective based on those criteria.

The Company's independent registered public accounting firm, KPMG LLP, has issued an audit report on the Company's internal control over financial reporting. This report appears on page 47 of this report.

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Item 8.Financial Statements and Supplementary Data
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Report of Independent Registered Public Accounting Firm
The Board of Directors and Shareholders
El Paso Electric Company:

We have audited the accompanying consolidated balance sheets of El Paso Electric Company and subsidiary as of December 31, 2011 and 2010, and the related consolidated statements of operations, comprehensive operations, changes in common stock equity, and cash flows for each of the years in the three-year period ended December 31, 2011. We also have audited El Paso Electric Company's internal control over financial reporting as of December 31, 2011, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). El Paso Electric Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on these consolidated financial statements and an opinion on the Company's internal control over financial reporting based on our audits.

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

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

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of El Paso Electric Company and subsidiary as of December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2011, in conformity with U.S. generally accepted accounting principles. Also in our opinion, El Paso Electric Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

/s/ KPMG LLP
Houston, Texas
February 24, 2012

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EL PASO ELECTRIC COMPANY AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS

ASSETS	December 31,	
(In thousands)	2011	2010
Utility plant:		
Electric plant in service	$2,789,773	$2,522,862
Less accumulated depreciation and amortization	(1,121,653)	(1,047,498)
Net plant in service	1,668,120	1,475,364
Construction work in progress	167,394	285,086
Nuclear fuel; includes fuel in process of $49,545 and $47,746, respectively	171,433	150,774
Less accumulated amortization	(59,882)	(45,471)
Net nuclear fuel	111,551	105,303
Net utility plant	1,947,065	1,865,753
Current assets:		
Cash and cash equivalents	8,208	79,184
Accounts receivable, principally trade, net of allowance for doubtful accounts of $3,015 and $2,885, respectively	76,348	71,685
Accumulated deferred income taxes	13,752	25,818
Inventories, at cost	40,222	36,132
Income taxes receivable	2,269	12,656
Undercollection of fuel revenues	9,130	—
Prepayments and other	4,810	4,543
Total current assets	154,739	230,018
Deferred charges and other assets:		
Decommissioning trust funds	167,963	153,878
Regulatory assets	101,027	88,557
Other	26,057	26,560
Total deferred charges and other assets	295,047	268,995
Total assets	$2,396,851	$2,364,766

See accompanying notes to consolidated financial statements.

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

CAPITALIZATION AND LIABILITIES	December 31,	
(In thousands except for share data)	2011	2010
Capitalization:		
Common stock, stated value $1 per share, 100,000,000 shares authorized, 65,295,888 and 65,121,689 shares issued, and 156,185 and 143,371 restricted shares, respectively	$65,452	$65,265
Capital in excess of stated value	309,777	305,068
Retained earnings	887,174	810,858
Accumulated other comprehensive loss, net of tax	(77,505)	(33,177)
	1,184,898	1,148,014
Treasury stock, 25,492,919 and 22,693,995 shares, respectively, at cost	(424,647)	(337,639)
Common stock equity	760,251	810,375
Long-term debt	816,497	849,745
Total capitalization	1,576,748	1,660,120
Current liabilities:		
Current maturities of long-term debt	33,300	—
Short-term borrowings under the revolving credit facility	33,379	4,704
Accounts payable, principally trade	51,704	41,795
Taxes accrued	30,700	29,172
Interest accrued	12,123	12,099
Overcollection of fuel revenues	2,105	18,976
Other	21,921	24,207
Total current liabilities	185,232	130,953
Deferred credits and other liabilities:		
Accumulated deferred income taxes	299,475	286,730
Accrued pension liability	129,627	93,471
Accrued postretirement benefit liability	100,455	61,594
Asset retirement obligation	56,140	92,911
Regulatory liabilities	21,049	14,489
Other	28,125	24,498
Total deferred credits and other liabilities	634,871	573,693
Commitments and contingencies		
Total capitalization and liabilities	$2,396,851	$2,364,766

See accompanying notes to consolidated financial statements.

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

	Years Ended December 31,		
	2011	2010	2009
Operating revenues	$918,013	$877,251	$827,996
Energy expenses:			
Fuel	223,507	199,829	185,837
Purchased and interchanged power	75,149	91,916	108,603
	298,656	291,745	294,440
Operating revenues net of energy expenses	619,357	585,506	533,556
Other operating expenses:			
Other operations	229,570	224,221	215,841
Maintenance	62,092	56,823	59,606
Depreciation and amortization	81,331	81,011	74,946
Taxes other than income taxes	55,561	54,489	49,998
	428,554	416,544	400,391
Operating income	190,803	168,962	133,165
Other income (deductions):			
Allowance for equity funds used during construction	8,161	10,816	9,311
Investment and interest income, net	5,664	5,315	3,813
Miscellaneous non-operating income	885	1,368	1,107
Miscellaneous non-operating deductions	(3,187)	(3,206)	(3,483)
	11,523	14,293	10,748
Interest charges (credits):			
Interest on long-term debt and revolving credit facility	54,115	50,826	50,512
Other interest	989	254	396
Capitalized interest	(5,177)	(2,487)	(943)
Allowance for borrowed funds used during construction	(4,848)	(6,671)	(6,029)
	45,079	41,922	43,936
Income before income taxes and extraordinary item	157,247	141,333	99,977
Income tax expense	53,708	51,016	33,044
Income before extraordinary item	103,539	90,317	66,933
Extraordinary gain related to Texas regulatory assets, net of tax	—	10,286	—
Net income	$103,539	$100,603	$66,933
Basic earnings per share:			
Income before extraordinary item	$2.49	$2.08	$1.50
Extraordinary gain related to Texas regulatory assets, net of tax	—	0.24	—
Net income	$2.49	$2.32	$1.50
Diluted earnings per share:			
Income before extraordinary item	$2.48	$2.07	$1.50
Extraordinary gain related to Texas regulatory assets, net of tax	—	0.24	—
Net income	$2.48	$2.31	$1.50
Dividends declared per share of common stock	$0.66	$—	$—
Weighted average number of shares outstanding	41,349,883	43,129,735	44,524,146
Weighted average number of shares and dilutive potential shares outstanding	41,587,059	43,294,419	44,595,067

See accompanying notes to consolidated financial statements.

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

	Years Ended December 31,		
	2011	2010	2009
Net income	$103,539	$100,603	$66,933
Other comprehensive income (loss):			
Unrecognized pension and postretirement benefit costs:			
Net loss arising during period	(77,678)	(9,874)	(48,580)
Prior service benefit	—	26,605	—
Reclassification adjustments included in net income for amortization of:			
Prior service cost	(5,812)	(2,754)	(2,754)
Net loss	6,505	3,374	1,625
Net unrealized gains on marketable securities:			
Net holding gains arising during period	1,570	6,665	12,816
Reclassification adjustments for net losses included in net income	1,358	122	2,218
Net losses on cash flow hedges:			
Reclassification adjustment for interest expense included in net income	361	338	317
Total other comprehensive income (loss) before income taxes	(73,696)	24,476	(34,358)
Income tax benefit (expense) related to items of other comprehensive income (loss):			
Unrecognized pension and postretirement benefit costs	30,134	(6,287)	16,957
Net unrealized gains on marketable securities	(563)	(1,357)	(3,007)
Losses on cash flow hedges	(203)	(122)	(115)
Total income tax benefit (expense)	29,368	(7,766)	13,835
Other comprehensive income (loss), net of tax	(44,328)	16,710	(20,523)
Comprehensive income	$59,211	$117,313	$46,410

See accompanying notes to consolidated financial statements.

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

	Common Stock		Capital in Excess of Stated Value	Retained Earnings	Accumulated Other Comprehensive Loss, Net of Tax	Treasury Stock		Common Stock Equity
	Shares	Amount				Shares	Amount	
Balances at December 31, 2008	64,732,652	$64,733	$295,346	$643,322	$ (29,364)	19,848,900	$(279,808)	$694,229
Restricted common stock grants and deferred compensation	114,703	115	2,162					2,277
Stock awards withheld for taxes	(8,249)	(8)	(157)					(165)
Forfeitures and lapsed restricted common stock	(12,850)	(13)						(13)
Deferred taxes on stock incentive plan			328					328
Stock options exercised	267,900	267	3,501					3,768
Net income				66,933				66,933
Other comprehensive loss					(20,523)			(20,523)
Treasury stock acquired, at cost						1,320,384	(24,105)	(24,105)
Balances at December 31, 2009	65,094,156	65,094	301,180	710,255	(49,887)	21,169,284	(303,913)	722,729
Restricted common stock grants and deferred compensation	112,891	113	2,302					2,415
Performance share awards vested	9,525	10	653					663
Stock awards withheld for taxes	(10,261)	(11)	(236)					(247)
Forfeitures and lapsed restricted common stock	(37,993)	(38)	(463)					(501)
Deferred taxes on stock incentive plan			350					350
Stock options exercised	96,742	97	1,282					1,379
Net income				100,603				100,603
Other comprehensive income					16,710			16,710

Treasury stock acquired, at cost						1,524,711	(33,726)	(33,726)
Balances at December 31, 2010	65,265,060	65,265	305,068	810,858	(33,177)	22,693,995	(337,639)	810,375
Restricted common stock grants and deferred compensation	118,110	118	3,087					3,205
Performance share awards vested	40,895	41	587					628
Stock awards withheld for taxes	(23,702)	(24)	(715)					(739)
Forfeitures and lapsed restricted common stock	(2,200)	(2)						(2)
Deferred taxes on stock incentive plan			1,112					1,112
Stock options exercised	53,910	54	638					692
Net income				103,539				103,539
Other comprehensive loss					(44,328)			(44,328)
Dividends declared				(27,223)				(27,223)
Treasury stock acquired, at cost						2,798,924	(87,008)	(87,008)
Balances at December 31, 2011	65,452,073	$65,452	$309,777	$887,174	$ (77,505)	25,492,919	$(424,647)	$760,251

See accompanying notes to consolidated financial statements.

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

	Years Ended December 31, 2011	2010	2009
Cash Flows From Operating Activities:			
Net income	$103,539	$100,603	$66,933
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization of electric plant in service	81,331	81,011	74,946
Amortization of nuclear fuel	37,018	31,316	22,305
Extraordinary gain related to Texas regulatory assets, net of tax	—	(10,286)	—
Deferred income taxes, net	45,688	27,456	40,846
Allowance for equity funds used during construction	(8,161)	(10,816)	(9,311)
Other amortization and accretion	19,875	16,740	14,440
Other operating activities	1,036	(881)	1,154
Change in:			
Accounts receivable	(4,663)	(1,303)	26,125
Inventories	(3,750)	1,143	2,135
Net overcollection (undercollection) of fuel revenues	(26,001)	958	64,875
Prepayments and other	(2,538)	(544)	(790)
Accounts payable	4,401	(9,634)	(1,988)
Taxes accrued	11,915	18,523	(17,704)
Interest accrued	24	1,816	2,764
Other current liabilities	(2,286)	(689)	750
Deferred charges and credits	(5,911)	(6,063)	(18,370)
Net cash provided by operating activities	251,517	239,350	269,110
Cash Flows From Investing Activities:			
Cash additions to utility property, plant and equipment	(178,041)	(169,966)	(209,974)
Cash additions to nuclear fuel	(39,551)	(34,277)	(34,904)
Capitalized interest and AFUDC:			
Utility property, plant and equipment	(13,009)	(17,487)	(15,340)
Nuclear fuel	(5,177)	(2,487)	(943)
Allowance for equity funds used during construction	8,161	10,816	9,311
Decommissioning trust funds:			
Purchases, including funding of $8.3 million, $8.2 million and $7.9 million, respectively	(95,441)	(73,192)	(90,118)
Sales and maturities	82,926	61,656	79,935
Proceeds from sale of investments in debt securities	2,000	—	—
Other investing activities	727	286	1,695
Net cash used for investing activities	(237,405)	(224,651)	(260,338)
Cash Flows From Financing Activities:			
Repurchases of common stock	(86,508)	(33,726)	(24,105)
Dividends paid	(27,223)	—	—
Proceeds from issuance of long-term debt	—	110,000	—
Borrowings under the revolving credit facility:			
Proceeds	120,450	37,628	186,471
Payments	(91,775)	(139,922)	(173,126)
Other financing activities	(32)	(1,285)	2,136

Net cash used for financing activities	(85,088)	(27,305)	(8,624)
Net increase (decrease) in cash and cash equivalents	(70,976)	(12,606)	148
Cash and cash equivalents at beginning of period	79,184	91,790	91,642
Cash and cash equivalents at end of period	$8,208	$79,184	$91,790

See accompanying notes to consolidated financial statements.

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INDEX TO NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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EL PASO ELECTRIC COMPANY AND SUBSIDIARY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

A. Summary of Significant Accounting Policies

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

Principles of Consolidation. The consolidated financial statements include the accounts of El Paso Electric Company and its wholly-owned subsidiary, MiraSol Energy Services, Inc. (“MiraSol”) (collectively, the “Company”). MiraSol, which began operations as a separate subsidiary in March 2001, provided energy efficiency products and discontinued these activities in 2002. All intercompany transactions and balances have been eliminated in consolidation.

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

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

Application of FASB Guidance for Regulated Operations. Regulated electric utilities typically prepare their financial statements in accordance with the Financial Accounting Standards Board (“FASB”) guidance for regulated operations. FASB guidance for regulated operations requires the Company to include an allowance for equity and borrowed funds used during construction (“AEFUDC” and “ABFUDC”) as a cost of construction of electric plant in service. AEFUDC is recognized as income and ABFUDC is shown as capitalized interest charges in the Company’s statement of operations. FASB guidance for regulated operations also requires the Company to show certain recoverable costs as either assets or liabilities on a utility’s balance sheet if the regulator provides assurance that these costs will be charged to and collected from the utility’s customers (or has already permitted such cost recovery) or will be credited or refunded to the utility’s customers. The resulting regulatory assets or liabilities are amortized in subsequent periods based upon the respective amortization periods reflected in a utility’s regulated rates. See Note D. The Company applies FASB guidance for regulated operations for all three of the jurisdictions in which it operates.

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

Comprehensive Income. Certain gains and losses that are not recognized currently in the consolidated statements of operations are reported as other comprehensive income in accordance with FASB guidance for reporting comprehensive income.

Utility Plant. Utility plant is generally reported at cost. The cost of renewals and betterments are capitalized and the costs of repairs and minor replacements are charged to the appropriate operating expense accounts. Depreciation is provided on a straight-line basis over the estimated remaining lives of the assets (ranging in average from 5 to 48 years). The average composite depreciation rate utilized in 2011, 2010 and 2009 was 2.80%, 3.21%, and 3.22%, respectively. When property subject to composite depreciation is retired or otherwise disposed of in the normal course of business, its cost – together with the cost of removal, less salvage – is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation is removed from the balance sheet accounts and a gain or loss is recognized.

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

See Note E.

Impairment of Long-Lived Assets. Long-lived assets are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability of assets to be held and used is measured by a comparison of the carrying amount of an asset to estimated undiscounted future cash flows expected to be generated by the asset. If the carrying amount of an asset exceeds its estimated undiscounted future cash flows, an impairment charge is recognized for the amount by which the carrying amount of the asset exceeds the fair value of the asset.

AFUDC and Capitalized Interest. The Company capitalizes interest (ABFUDC) and common equity (AEFUDC) costs to construction work in progress and capitalizes interest to nuclear fuel in process in accordance with the FERC Uniform System of Accounts as provided for in FASB guidance. AFUDC is a non-cash component of income and is calculated monthly and charged to all new eligible construction and capital improvement projects. AFUDC is compounded on a monthly basis. The AFUDC rate used in 2011 was 8.54% . The AFUDC rate utilized for the first six months of 2010 was 9.01% and 8.47% thereafter. The AFUDC rate utilized in 2009 was 8.94%.

Asset Retirement Obligation. FASB guidance sets forth accounting requirements for the recognition and measurement of liabilities associated with the retirement of tangible long-lived assets. An asset retirement obligation ("ARO") associated with long-lived assets included within the scope of FASB guidance is that for which a legal obligation exists under enacted laws, statutes, written or oral contracts, including obligations arising under the doctrine of promissory estoppel and legal obligations to perform an asset retirement activity even if the timing and/or settlement are conditioned on a future event that may or may not be within the control of an entity. See Note F. Under FASB guidance, these liabilities are recognized as incurred if a reasonable estimate of fair value can be established and are capitalized as part of the cost of the related tangible long-lived assets. The Company records the increase in the ARO due to the passage of time as an operating expense (accretion expense).

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

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

Derivative Accounting. Accounting for derivative instruments and hedging activities requires the recognition of derivatives as either assets or liabilities in the balance sheet with measurement of those instruments at fair value. Any changes in the fair value of these instruments are recorded in earnings or other comprehensive income. See Note O.

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

Operating Revenues Net of Energy Expenses. The Company accrues revenues for services rendered, including unbilled electric service revenues. Energy expenses are stated at actual cost incurred. The Company's Texas retail customers are billed under base rates and a fixed fuel factor approved by the PUCT. The Company's New Mexico retail customers and its sales for resale customer are billed under base rates and a fuel adjustment clause which is adjusted monthly, as approved by the New Mexico Public Regulation Commission ("NMPRC") and the FERC. The Company's recovery of energy expenses is subject to periodic reconciliations of actual energy expenses incurred to actual fuel revenues collected. The difference between energy expenses incurred and fuel revenues charged to customers is reflected as over/undercollection of fuel revenues in the consolidated balance sheets. See Note C.

Revenues. Revenues related to the sale of electricity are generally recorded when service is rendered or electricity is delivered to customers. The billing of electricity sales to retail customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. Unbilled revenues are estimated based on monthly generation volumes and by applying an average revenue/kWh to the number of estimated kWhs delivered but not billed. Accounts receivable included accrued unbilled revenues of $19.6 million and $16.6 million at December 31, 2011 and 2010, respectively. The Company presents revenues net of sales taxes in its consolidated statements of operations.

Allowance for Doubtful Accounts. The allowance for doubtful accounts represents the Company's estimate of existing accounts receivable that will ultimately be uncollectible. The allowance is calculated by applying estimated write-off factors to various classes of outstanding receivables. The write-off factors used to estimate uncollectible accounts are based upon consideration of both historical collections experience and management's best estimate of future collections success given the existing collections environment. Additions, deductions and balances for allowance for doubtful accounts for 2011, 2010 and 2009 are as follows (in thousands):

	2011	2010	2009
Balance at beginning of year	$2,885	$1,191	$3,123
Additions:			
Charged to costs and expense	6,209	4,756	3,289
Recovery of previous write-offs	2,034	852	1,316
Uncollectible receivables written off	8,113	3,914	6,537
Balance at end of year	$3,015	$2,885	$1,191

Income Taxes. The Company accounts for federal and state income taxes under the asset and liability method of accounting for income taxes. Deferred income taxes are recognized for the estimated future tax consequences of "temporary differences" by applying enacted statutory tax rates for each taxable jurisdiction applicable to future years to differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities. The effect on deferred tax assets and liabilities of a change in tax rate is recognized in income in the period that includes the enactment date. The Company recognizes tax assets and liabilities for uncertain tax positions in accordance with the recognition and measurement criteria of FASB guidance for uncertainty in income taxes. See Note J.

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

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

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

Reclassification. Certain amounts in the consolidated financial statements for 2010 and 2009 have been reclassified to conform with the 2011 presentation.

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 would have been 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 could require additional disclosure on the Company's statement of operations and related notes. In December 2011, the FASB issued new guidance to defer the effective date for amendments to the presentation of reclassification of items out of accumulated other comprehensive income. Deferring the effective date will allow the FASB time to redeliberate whether to present on the face of the financial statements the effects of reclassifications out of accumulated other comprehensive income on the components of net income and other comprehensive income for all periods presented. While the FASB is considering the operational concerns about the presentation requirements for reclassification adjustments and the needs of financial statement users for additional information about reclassification adjustments, the Company will continue to report reclassifications out of accumulated other comprehensive income consistent with the presentation requirements in effect before the guidance issued in June 2011 until further guidance becomes available.

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. 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.

2012 Texas Retail Rate Case. The Company filed a request with the PUCT (Docket No. 40094), the City of El Paso, and other Texas cities on February 1, 2012 for a $26.3 million increase in rates charged to customers in Texas. The rate filing was made in response to a resolution adopted by the El Paso City Council requiring the Company to show cause why its base rates for customers in the El Paso city limits should not be reduced. The City has until August 4, 2012 to make a determination regarding the Company's base rates in the City of El Paso. The rate filing used a historical test year ended September 30, 2011, adjusted for known and measurable items, and a return on equity of 10.6%. The filing at the PUCT also includes a request to reconcile $356.5 million of fuel expense for the period July 1, 2009 through September 30, 2011.

On November 15, 2011, the El Paso City Council adopted a resolution which established current rates as temporary rates for the Company's customers residing within the city limits of El Paso. Temporary rates will be effective from November 15, 2011 until a final determination is made by the PUCT on the Company's rates in the rate proceeding initiated by the City's Show Cause Order. Upon a final determination by the PUCT, the PUCT may order a refund to customers of money collected in excess of the rate finally ordered, including interest, or shall authorize the Company to surcharge bills to recover the amount, including interest, by which the money collected under the temporary rates is less than the money that would have been collected under the rate finally ordered. The rates proposed by the Company in the Texas rate case included increases for some customer classes and decreases for other customer classes. As a result, consistent implementation of the proposed rates may require the PUCT to reflect the differences in temporary and final rates from November 15, 2011 for each affected class.

While cities in Texas have jurisdiction over rates in their city limits, the PUCT has appellate authority over city rate decisions on a “de novo” basis; therefore, the ultimate authority to set the Company's Texas electric rates is vested in the PUCT. The Company cannot predict the outcome of this proceeding. If the rate case results in implementing lower rates, the resulting lower rates would have a negative impact on the Company's revenues, net income and cash from operations.

Fuel Reconciliation Case (Severed from 2009 Rate Case). Pursuant to the stipulation in the Company's 2009 rate case, the PUCT established Docket No. 38361 to address the 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 which adjusts natural gas and purchased power to reflect natural gas futures prices. 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 billing month(s) in which customers received the refund amounts shown, including interest:

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Docket No.	Date Filed	Date Approved	Recovery Period	Refund Period	Refund Amount (In thousands)
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

As noted above, the rate filing filed with the PUCT on February 1, 2012 (Docket No. 40094), includes a request to reconcile $356.5 million of fuel expense for the period July 1, 2009 through September 30, 2011. However, this filing does not request a change in the fixed fuel factor.

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. A final order was issued January 12, 2012 revising the MBDRF to 0.936% and allowing $3.9 million dollars of under-recovered discount charges to begin February 1, 2012.

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. 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 passed a motion that, upon the conclusion of other hearings and investigations into the extreme cold weather event, the Mayor would call for Special City Council meetings or public hearings to evaluate how the three utility companies operating within the city, including the Company, performed during the extreme weather event. The El Paso City Council retained a consultant to assess the Company's activities during the weather event and the Company's subsequent actions to prevent outages during a similar future event. The El Paso City Council's consultant presented the following three recommendations to the El Paso City Council on December 20, 2011: (i) request the Company to prepare and present an updated reliability study; (ii) request the Company and El Paso Water Utilities to present their coordinated plans for power and water supply to critical loads during severe weather events; and (iii) request the Company to file an updated emergency operations plan with both the PUCT and the El Paso City Council which will be completed in 2012. The El Paso City Council unanimously passed a motion to approve the three recommendations. At the January 10, 2012 El Paso City Council Meeting, the Company presented information requested in recommendations (i) and (ii) above.

Application of El Paso Electric Company to Amend its Certificate of Convenience and Necessity for Five Solar Power Generation Projects. On December 9, 2011, the Company filed a petition seeking a CCN to construct five solar powered generation projects, totaling approximately 2.6MW, at four locations within the City of El Paso and one location in the Town of Van Horn. This case was assigned PUCT Docket No. 39973 and is still pending.

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. A final order was issued on November 22, 2011 in which the NMPRC did not adopt the unopposed stipulation, but modified the structure of the energy rider to reduce the return to two percent and made the mechanism temporary. The Company filed a Notice of Appeal with the Supreme Court of the State of New Mexico on January 20, 2012 on the grounds that the NMPRC's decision is arbitrary and without substantial evidence.

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 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 January 25, 2012, a hearing examiner issued a recommended decision modifying the stipulation by approving the Energy Efficiency programs and budgets with the exception of the Commercial Lighting Program, approving the adder for 2011 but not for 2012 or 2013 and excluding the Military Research & Development Class from participation in the rate rider and reducing the Company's required saving goals accordingly. On February 2, 2012, the Company filed certain exceptions to the recommended decision and requested an interim order related to this matter.

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 Renewable Procurement 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 2011 Renewable Procurement 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. A final order was issued on December 15, 2011 approving the 2011 Renewable Procurement Plan.

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. Obtaining the ability to issue up to $300 million of new long-term debt, from time to time, provides the Company with the flexibility to access the debt capital markets when needed and when conditions are favorable.

On November 15, 2011, the Company and Rio Grande Resources Trust ("RGRT") amended and restated the $200 million unsecured RCF with JP Morgan Chase Bank, N.A., as administrative agent and issuing bank, and Union Bank, N.A., as syndication agent, and various lending banks party thereto. The amended and restated RCF reduces borrowing costs and extends the maturity from September 2014 to September 2016. The Company still has the ability to request that the RCF be increased to $300 million during the term of the RCF, subject to lender's approval. All other terms remain substantially the same.

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.

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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 that 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. Those two new service agreements were entered into and became effective November 1, 2011. Also under the terms of the settlement, TEP made a lump-sum cash payment to the Company of approximately $5.4 million 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. As part of the settlement, the Company withdrew 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. As part of the settlement, this lawsuit was dismissed.

With the implementation of the settlement effective November 1, 2011, these matters between the Company and TEP were fully resolved.

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, where it made recommendations to help prevent a recurrence of such outages in the future, and making no finding of violations or assessments of penalties.

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. Obtaining the ability to issue up to $300 million of new long-term debt, from time to time, provides the Company with the flexibility to access the debt capital markets when needed and when conditions are favorable.

On November 15, 2011, the Company and RGRT amended and restated the $200 million unsecured RCF with JP Morgan Chase Bank, N.A., as administrative agent and issuing bank, and Union Bank, N.A., as syndication agent, and various lending banks party thereto. The amended and restated RCF reduces borrowing costs and extends the maturity from September 2014 to September 2016. The Company still has the ability to request that the RCF be increased to $300 million, subject to lender's approval. All other terms remain substantially the same.

Department of Energy. The DOE regulates the Company's exports of power to the Comisión Federal de Electricidad in Mexico pursuant to a license granted by the DOE and a presidential permit.

The DOE is authorized to assess operators of nuclear generating facilities a share of the costs of decommissioning the DOE's uranium enrichment facilities and for the ultimate costs of disposal of spent nuclear fuel. See Note E for discussion of

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spent fuel storage and disposal costs.

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

Sales for Resale

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

D. Regulatory Assets and Liabilities

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

	Amortization Period Ends	December 31, 2011	December 31, 2010
Regulatory assets			
Regulatory tax assets (a)	(b)	$52,281	$37,230
Loss on reacquired debt (c)	May 2035	20,044	20,897
Final coal reclamation (a)	July 2016	6,655	10,282
Nuclear fuel postload daily financing charge	(d)	3,470	2,007
Unrecovered issuance costs due to reissuance of PCBs (c)	April 2040	578	599
Texas energy efficiency	(e)	4,497	5,460
Texas 2009 rate case costs (f)	June 2012	1,146	3,298
Texas 2012 rate case costs	(g)	648	—
Texas military base discount and recovery factor	(h)	2,526	761
New Mexico 2009 rate case procurement plan costs (f)	December 2011	—	232
New Mexico procurement plan costs	(g)	139	122
New Mexico 2009 rate case renewable energy credits (f)	December 2011	—	1,139
New Mexico renewable energy credits	(g)	2,884	930
New Mexico 2009 rate case costs (f)	December 2012	253	506
New Mexico 2010 FPPCAC audit	(g)	427	—
New Mexico Palo Verde deferred depreciation	(b)	5,176	4,773
New Mexico energy efficiency	(e)	303	321
Total regulatory assets		$101,027	$88,557
Regulatory liabilities			
Regulatory tax liabilities (a)	(b)	$16,138	$9,326
Accumulated deferred investment tax credit (i)	(b)	4,911	5,163

Total regulatory liabilities	$21,049	$14,489

(a) No specific return on investment is required since related assets and liabilities, including accumulated deferred income taxes and reclamation liability, offset.
(b) The amortization period for this asset is based upon the life of the associated assets.

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(c) This item is recovered as a component of the weighted cost of debt and amortized over 30 years beginning in 2005.
(d) This item is recovered through fuel recovery mechanisms.
(e) This asset is recovered through an annual recovery factor.
(f) This item is included in rate base which earns a return on investment.
(g) Amortization period is anticipated to be established in next general rate case.
(h) This item represents the net asset related to the military discount which is recovered from non-military customers through a recovery factor.
(i) This item is excluded from rate base.

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

The table below presents the balance of each major class of depreciable assets at December 31, 2011 (in thousands):

	Gross Plant	Accumulated Depreciation	Net Plant
Nuclear production	$768,284	$(240,862)	$527,422
Steam and other	557,286	(223,109)	334,177
Total production	1,325,570	(463,971)	861,599
Transmission	394,385	(238,940)	155,445
Distribution	864,746	(308,644)	556,102
General	141,921	(78,323)	63,598
Intangible	63,151	(31,775)	31,376
Total	$2,789,773	$(1,121,653)	$1,668,120

Amortization of intangible plant (software) is provided on a straight-line basis over the estimated useful life of the asset (ranging from 5 to 10 years). The table below presents the actual and estimated amortization expense for intangible plant for the previous three years and for the next five years (in thousands):

2009	$4,542
2010	6,312
2011	6,668
2012 (estimated)	6,124
2013 (estimated)	5,403
2014 (estimated)	4,292
2015 (estimated)	3,542
2016 (estimated)	3,045

The Company owns a 15.8% interest in each of the three nuclear generating units and common facilities at Palo Verde, in Wintersburg, Arizona. The Palo Verde Participants include the Company and six other utilities: Arizona Public Service Company (“APS”), Southern California Edison Company (“SCE”), Public Service Company of New Mexico (“PNM”), Southern California Public Power Authority, Salt River Project Agricultural Improvement and Power District (“SRP”) and the Los Angeles Department of Water and Power.

Other jointly-owned utility plant includes a 7% interest in Units 4 and 5 at Four Corners Generating Station (“Four Corners”) and certain other transmission facilities. A summary of the Company’s investment in jointly-owned utility plant, excluding fuel inventories, at December 31, 2011 and 2010 is as follows (in thousands):

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	December 31, 2011		December 31, 2010	
	Palo Verde	Other	Palo Verde	Other
Electric plant in service	$768,284	$211,983	$772,710	$209,427
Accumulated depreciation	(240,862)	(164,622)	(225,461)	(159,679)
Construction work in progress	53,822	1,634	48,703	1,940
Total	$581,244	$48,995	$595,952	$51,688

Palo Verde

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

NRC. The NRC regulates the operation of all commercial nuclear power reactors in the United States, including Palo Verde. The NRC periodically conducts inspections of nuclear facilities and monitors performance indicators to enable the agency to arrive at objective conclusions about a licensee's safety performance.

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 last three quarters of 2011 combined, the extension of the operating licenses had the effect of reducing depreciation and amortization expense by approximately $8.2 million and reducing the accretion expense on the Palo Verde asset retirement obligation by approximately $3.1 million.

Decommissioning. Pursuant to the ANPP Participation Agreement and federal law, the Company must fund its share of the estimated costs to decommission Palo Verde Units 1, 2 and 3, including the Common Facilities, through the term of their respective operating licenses. The Company is required to maintain a minimum accumulation and a minimum funding level in its decommissioning account at the end of each annual reporting period during the life of the plant. The Company has established external trusts with an independent trustee, which enables the Company to record a current deduction for federal income tax purposes for most of the amounts funded. At December 31, 2011, the Company's decommissioning trust fund had a balance of $168.0 million, and the Company was above its minimum funding level. The Company will continue to monitor the status of its decommissioning funds and adjust its deposits, if necessary, to remain at or above its minimum accumulation requirements in the future.

Decommissioning costs are estimated every three years based upon engineering cost studies performed by outside engineers retained by APS. On March 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 of $33.0 million (stated in 2010 dollars) from the 2007 Palo Verde decommissioning study (the "2007 Study"). The net effect of these changes lowered the asset retirement obligation by $41.7 million and will lower annual expenses in the future. 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. See "Spent Fuel Storage" and "Disposal of Low-Level Radioactive Waste" below.

Spent Fuel Storage. The original spent fuel storage facilities at Palo Verde had sufficient capacity to store all fuel discharged from normal operation of all three Palo Verde units through 2003. Alternative on-site storage facilities and casks have been constructed to supplement the original facilities. In March 2003, APS began removing spent fuel from the original facilities as necessary, and placing it in special storage casks which will be stored at the on-site facilities until accepted by the DOE for permanent disposal. The 2010 Study assumed that costs to store fuel on-site will become the responsibility of the DOE after 2057. APS believes that spent fuel storage or disposal methods will be available to allow each Palo Verde unit to continue to operate through the current term of its operating license.

Pursuant to the Nuclear Waste Policy Act of 1982, as amended in 1987 (the “Waste Act”), the DOE is legally obligated to accept and dispose of all spent nuclear fuel and other high-level radioactive waste generated by all domestic power reactors. In accordance with the Waste Act, the DOE entered into a spent nuclear fuel contract with the Company and all other Palo Verde Participants. The DOE has previously reported that its spent nuclear fuel disposal facilities would not be in operation in the near future. In November 1997, the United States Court of Appeals for the District of Columbia Circuit issued a decision preventing the DOE from excusing its own delay but refused to order the DOE to begin accepting spent nuclear fuel. The Company cannot predict when spent fuel shipments to the DOE will commence.

The Company expects to incur significant costs for on-site spent fuel storage during the life of Palo Verde that the Company believes are the responsibility of the DOE. These costs are assigned to fuel requiring the additional on-site storage and amortized as that fuel is burned until an agreement is reached with the DOE for recovery of these costs.

In December 2003, APS, in conjunction with other nuclear plant operators, filed suit against the DOE on behalf of the Palo Verde Participants to recover monetary damages associated with the delay in the DOE’s acceptance of spent fuel. APS pursued a damages claim for costs incurred through December 2006 in a trial that began on January 28, 2009. On June 18, 2010, the court awarded APS and the other Palo Verde Participants approximately $30 million. In October 2010, the Company received $4.8 million, representing its share of the award. The majority of the award was refunded to customers through the applicable fuel adjustment clauses. APS is continuing to pursue settlement of damage claims for costs incurred after 2006.

Disposal of Low-level Radioactive Waste. Congress has established requirements for the disposal by each state of low-level radioactive waste generated within its borders. The construction and opening of low-level radioactive waste disposal sites have been delayed due to extensive public hearings, disputes over environmental issues and review of technical issues related to the proposed sites. The opposition, delays, uncertainty and costs that have been experienced demonstrate possible roadblocks that may be encountered when Arizona seeks to open its own waste repository. APS currently believes that interim low-level waste storage methods are or will be available to allow each Palo Verde unit to continue to operate and to store safely low-level waste until a permanent disposal facility is available.

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.

Following the March 11, 2011 earthquake and tsunami in Japan, the NRC launched a two-pronged review of U.S. nuclear power plant safety. The NRC supported the establishment of an agency task force to conduct both a near- and long-term analysis of the lessons that can be learned from the situation in Japan. The near-term task force issued a report on July 12, 2011, and on October 3, 2011, the NRC staff issued a plan for implementing the near-term task force's recommendations.

On October 18, 2011, the NRC Commissioners directed the NRC staff to implement, without delay, the near-term task force recommendations, subject to certain conditions. One such condition is that the agency should strive to complete and implement lessons learned from the earthquake and tsunami in Japan within five years. A second condition is that the staff should designate the recommendation for a rulemaking to address extended loss of offsite power to be completed within 24 to 30 months.

Until further action is taken by the NRC as a result of this event, the Company cannot predict any financial or operational impacts on Palo Verde.

Liability and Insurance Matters. The Palo Verde participants have insurance for public liability resulting from nuclear energy hazards to the full limit of liability under federal law, which is currently at $12.6 billion. This potential liability is covered by primary liability insurance provided by commercial insurance carriers in the amount of $375 million, and the balance is covered by an industry-wide retrospective assessment program. If a loss at a nuclear power plant covered by the programs exceeds the accumulated funds in the primary level of protection, the Company could be assessed retrospective premium adjustments on a per incident basis. Under federal law, the maximum assessment per reactor under the program for each nuclear incident is approximately $117.5 million, subject to an annual limit of $17.5 million. Based upon the Company's 15.8% interest in the three Palo Verde units, the Company's maximum potential assessment per incident for all three units is approximately $55.7 million, with an annual payment limitation of approximately $8.3 million.

The Palo Verde Participants maintain “all risk” (including nuclear hazards) insurance for property damage to, and decontamination of, property at Palo Verde in the aggregate amount of $2.75 billion, a substantial portion of which must first be applied to stabilization and decontamination. The Company has also secured insurance against portions of any increased cost of generation or purchased power and business interruption resulting from a sudden and unforeseen outage of any of the three units. The insurance coverage discussed in this and the previous paragraph is subject to certain policy conditions and exclusions. A mutual insurance company whose members are utilities with nuclear facilities issues these policies. If losses at any nuclear facility covered by this mutual insurance company were to exceed the accumulated funds for these insurance programs, the Company could be assessed retrospective premium adjustments of up to $9.57 million for the current policy period.

F. Accounting for Asset Retirement Obligations

The Company complies with FASB guidance for asset retirement obligations (“ARO”). This guidance affects the accounting for the decommissioning of the Company’s Palo Verde and Four Corners Stations and the method used to report the decommissioning obligation. The Company also complies with FASB guidance for conditional asset retirements which primarily affects the accounting for the disposal obligations of the Company’s fuel oil storage tanks, water wells, evaporative ponds and asbestos found at the Company’s gas-fired generating plants. The Company’s AROs are subject to various assumptions and determinations such as: (i) whether a legal obligation exists to remove assets; (ii) estimation of the fair value of the costs of removal; (iii) when final removal will occur; (iv) future changes in decommissioning cost escalation rates; and (v) the credit-adjusted interest rates to be utilized in discounting future liabilities. Changes that may arise over time with regard to these assumptions and determinations will change amounts recorded in the future as an expense for AROs. The Company records the increase in the ARO due to the passage of time as an operating expense (accretion expense). If the Company incurs or assumes any liability in retiring any asset at the end of its useful life without a legal obligation to do so, it will record such retirement costs as incurred.

The 2011 ARO liability for Palo Verde is based upon the estimated cost of decommissioning the plant from the 2010 Palo Verde decommissioning study. See Note E. The ARO liability is calculated by adjusting the estimated decommissioning costs for spent fuel storage and a profit margin and market-risk premium factor. The resulting costs are escalated over the remaining life of the plant and finally discounted using a credit-risk adjusted discount rate. As Palo Verde approaches the end of its estimated useful life, the difference between the ARO liability and future current cost estimates will narrow over time due to the accretion of the ARO liability. Because the DOE is obligated to assume responsibility for the permanent disposal of spent fuel, spent fuel costs have not been included in the ARO calculation. The Company has six external trust funds with an independent trustee that are legally restricted to settling its ARO at Palo Verde. The fair value of the funds at December 31, 2011 is $168.0 million.

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. Any changes that result in an upward revision to estimated cash flows shall be treated as a new liability. Any downward revisions to the estimated cash flows result in a reduction to the previously recorded ARO. In April 2011, the Company implemented the 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 E). 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	%

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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	2009
ARO liability at beginning of year	$92,911	$85,358	$78,037
Liabilities incurred	—	—	—
Liabilities settled	(793)	(85)	—
Revisions to estimate	(41,670)	(377)	—
Accretion expense	5,692	8,015	7,321
ARO liability at end of year	$56,140	$92,911	$85,358

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

G. Common Stock

Overview

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

Long-Term Incentive Plan

On May 2, 2007, the Company’s shareholders approved a stock-based long-term incentive plan (the “2007 LTIP”) and authorized the issuance of up to one million shares of common stock for the benefit of directors and employees. Under the 2007 LTIP, common stock may be issued through the award or grant of non-statutory stock options, incentive stock options, stock appreciation rights, restricted stock, bonus stock, performance stock, cash-based awards and other stock-based awards. The Company may issue new shares, purchase shares on the open market, or issue shares from shares the Company has repurchased to meet the share requirements of the 2007 LTIP. As discussed in Note A, the Company accounts for its stock-based long-term incentive plan under FASB guidance for stock-based compensation.
Stock Options. Stock options have been granted at exercise prices equal to or greater than the market value of the underlying shares at the date of grant. The fair value for these options was estimated at the grant date using the Black-Scholes option pricing model. The options expire ten years from the date of grant unless terminated earlier by the Board of Directors (the “Board”). Stock options have not been granted since 2003.

The following table summarizes the transactions in the Company’s stock options for 2011:

	Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value	Cash Received	Realized Current Tax Benefits
				(In thousands)	(In thousands)	(In thousands)
Options outstanding at December 31, 2010	101,246	$12.82				
Options exercised	53,910	12.83			$ 692	$327

Options outstanding at December 31, 2011	47,336	12.80	0.99	$ 1,034
Exercisable at December 31, 2011	47,336	12.80	0.99	1,034

The intrinsic value of stock options exercised in 2011, 2010 and 2009 were $1.0 million, $1.3 million and $1.5 million, respectively. No options were forfeited, vested or expired during 2011 and 2010.

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All stock options outstanding have vested. No compensation cost was recognized in 2009, 2010 and 2011 for stock options and there is no unrecognized compensation expense related to stock options.
Restricted Stock. The Company has awarded restricted stock under its long-term incentive plan. Restrictions from resale generally lapse and awards vest over periods of one to three years. The market value of the unvested restricted stock at the date of grant is amortized to expense over the restriction period net of anticipated forfeitures.
The expense, deferred tax benefit, and current tax expense recognized related to restricted stock awards in 2011, 2010 and 2009 is presented below (in thousands):

	2011	2010	2009
Expense	$2,258	$1,589	$1,537
Deferred tax benefit	790	556	538
Current tax expense (benefit) recognized (a)	(518)	(169)	134

(a) Any capitalized costs related to these expenses would be less than $0.1 million for all years.

The aggregate intrinsic value and fair value at grant date of restricted stock which vested in 2011, 2010 and 2009 is presented below (in thousands):

	2011	2010	2009
Aggregated intrinsic value	$3,279	$1,749	$1,331
Fair value at grant date	1,799	1,265	1,714

The unvested restricted stock transactions for 2011 are presented below:

	Total Shares	Weighted Average Grant Date Fair Value	Unrecognized Compensation Expense (a)	Aggregate Intrinsic Value
			(In thousands)	(In thousands)
Restricted shares outstanding at December 31, 2010	143,371	$18.30		
Restricted stock awards	118,110	28.98		
Lapsed restrictions and vesting	(103,096)	17.45		
Forfeitures	(2,200)	23.20		
Restricted shares outstanding at December 31, 2011	156,185	26.87	$2,136	$5,410

(a) The unrecognized compensation expense is expected to be recognized over the weighted average remaining contractual term of the outstanding restricted stock of approximately two years.
The weighted average fair values per share at grant date for restricted stock awarded during 2011, 2010 and 2009 were:

	2011	2010	2009
Weighted average fair value per share	$28.98	$20.03	$14.59

The holder of a restricted stock award has rights as a shareholder of the Company, including the right to vote and receive cash dividends on restricted stock.

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Performance Shares. The Company has granted performance share awards to certain officers under the Company's existing long-term incentive plan, which provides for issuance of Company stock based on the achievement of certain performance criteria over a three-year period. The payout varies between 0% to 200% of performance share awards. Detail of performance shares vested follows:

Date Vested	Payout Ratio	Performance Shares Awarded	Compensation Costs Expensed (In thousands)	Compensation Costs Expensed Period	Aggregated Intrinsic Value (In thousands)
January 1, 2012	175.0 %	174,038	$ 1,193	2009-2011	$ 6,029
July 9, 2011	112.5 %	2,250	23	2008-2011	75
September 3, 2011	112.5 %	3,825	40	2008-2011	129
January 1, 2011	112.5 %	34,820	565	2008-2010	959
January 1, 2010	30.0 %	9,525	662	2007-2009	193

In 2012, 2013 and 2014, subject to meeting certain performance criteria, additional performance shares could be awarded. In accordance with FASB guidance related to stock-based compensation, the Company recognizes the related compensation expense by ratably amortizing the grant date fair value of awards over the requisite service period and the compensation expense is only adjusted for forfeitures. Excluding the 174,038 shares that vested on January 1, 2012, the actual number of shares to be issued can range from zero to 392,328 shares.

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

The outstanding performance share awards at the 100% performance level is summarized below:

	Number Outstanding	Weighted Average Grant Date Fair Value	Unrecognized Compensation Expense (a) (in thousands)	Aggregate Intrinsic Value (in thousands)
Performance shares outstanding at December 31, 2010	219,800	$ 15.86		
Performance share awards	112,164	23.45		
Performance shares vested	(36,350)	17.27		
Performance shares lapsed	—	—		
Performance shares forfeited	—	—		
Performance shares outstanding at December 31, 2011	295,614	18.57	$ 1,825	$ 10,240

(a) The unrecognized compensation expense is expected to be recognized over the weighted average remaining contractual term of the awards of approximately one year.

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A summary of information related to performance shares for 2011, 2010 and 2009 is presented below:

	2011	2010	2009
Weighted average per share grant date fair value per share of performance shares awarded	$23.45	$19.82	$12.00
Fair value of performance shares vested (in thousands)	628	663	—
Intrinsic value of performance shares vested (in thousands)	1,032	193	—
Compensation expense (in thousands) (a)	1,573	988	727
Deferred tax expense related to compensation expense (in thousands)	551	346	254

(a) Includes cumulative adjustments for forfeiture of performance share awards by certain executives.

Repurchase Program

Detail regarding the Company's stock repurchase program are presented below:

	Since 1999 (a)	Twelve Months Ended December 31,	Authorized Shares
Shares repurchased	25,406,184	2,782,455	
Cost, including commission (in thousands)	$423,647	$86,508	
2010 Plan balance at December 31, 2010			676,271
2011 Plan repurchase shares authorized (b)			2,500,000
Total remaining shares available for repurchase at December 31, 2011			393,816

(a) Represents repurchased shares and cost since inception of the stock repurchase program in 1999.
(b) 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 program in open market transactions at prevailing prices and may engage in private transactions where appropriate. The repurchased shares will be available for issuance under employee benefit and stock incentive plans, or may be retired.

Dividend Policy

On December 30, 2011, the Company paid $8.8 million of quarterly dividends to shareholders. The Company paid a total of $27.2 million in cash dividends during the twelve months ended December 31, 2011. On January 26, 2012, the Board of Directors declared a quarterly cash dividend of $0.22 per share payable on March 30, 2012 to shareholders of record on March 15, 2012.

Basic and Diluted Earnings Per Share

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

	Years Ended December 31,		
	2011	2010	2009
Weighted average number of common shares outstanding:			
Basic number of common shares outstanding	41,349,883	43,129,735	44,524,146
Dilutive effect of unvested performance awards	206,658	101,780	27,876
Dilutive effect of stock options	30,518	62,904	43,045
Diluted number of common shares outstanding	41,587,059	43,294,419	44,595,067
Basic net income per common share:			
Net income	$103,539	$100,603	$66,933
Income allocated to participating restricted stock	(471)	(403)	(240)
Net income available to common shareholders	$103,068	$100,200	$66,693
Diluted net income per common share:			
Net income	$103,539	$100,603	$66,933
Income reallocated to participating restricted stock	(469)	(401)	(240)
Net income available to common shareholders	$103,070	$100,202	$66,693
Basic net income per common share:			
Distributed earnings	$0.66	$—	$—
Undistributed earnings	1.83	2.32	1.50
Basic net income per common share	$2.49	$2.32	$1.50
Diluted net income per common share:			
Distributed earnings	$0.66	$—	$—
Undistributed earnings	1.82	2.31	1.50
Diluted net income per common share	$2.48	$2.31	$1.50

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:

	Year Ended December 31,		
	2011	2010	2009
Restricted stock awards	81,653	75,270	66,628
Performance shares (a)	—	24,225	161,842
Stock options	—	—	53,610

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

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H. Accumulated Other Comprehensive Loss

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

	Net Unrealized Gains (Losses) on Marketable Securities	Unrecognized Pension and Postretirement Benefit Costs	Net Losses on Cash Flow Hedges	Accumulated Other Comprehensive Loss
Balance at December 31, 2008	$ (6,159)	$ (9,834)	$ (13,371)	$ (29,364)
Other comprehensive income (loss)	15,034	(49,709)	317	(34,358)
Income tax benefit (expense)	(3,007)	16,957	(115)	13,835
Balance at December 31, 2009	5,868	(42,586)	(13,169)	(49,887)
Other comprehensive income	6,787	17,351	338	24,476
Income tax expense	(1,357)	(6,287)	(122)	(7,766)
Balance at December 31, 2010	11,298	(31,522)	(12,953)	(33,177)
Other comprehensive income (loss)	2,928	(76,985)	361	(73,696)
Income tax benefit (expense)	(563)	30,134	(203)	29,368
Balance at December 31, 2011	$ 13,663	$ (78,373)	$ (12,795)	$ (77,505)

I. Long-Term Debt and Financing Obligations

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

	December 31, 2011	2010
	(In thousands)	
Long-Term Debt:		
Pollution Control Bonds (1):		
7.25% 2009 Series A refunding bonds, due 2040 (7.46% effective interest rate)	$63,500	$63,500
4.80% 2005 Series A refunding bonds, due 2040 (5.32% effective interest rate)	59,235	59,235
7.25% 2009 Series B refunding bonds, due 2040 (7.49% effective interest rate)	37,100	37,100
4.00% 2002 Series A refunding bonds, due 2032 (5.07% effective interest rate)	33,300	33,300
Total Pollution Control Bonds	193,135	193,135
Senior Notes (2):		
6.00% Senior Notes, net of discount, due 2035 (7.12% effective interest rate)	397,894	397,856
7.50% Senior Notes, net of discount, due 2038 (7.67% effective interest rate)	148,768	148,754
Total Senior Notes	546,662	546,610
RGRT Senior Notes (3):		
3.67% Senior Notes, Series A, due 2015 (3.87% effective interest rate)	15,000	15,000
4.47% Senior Notes, Series B, due 2017 (4.62% effective interest rate)	50,000	50,000
5.04% Senior Notes, Series C, due 2020 (5.16% effective interest rate)	45,000	45,000
Total RGRT Senior Notes	110,000	110,000
Total long-term debt	849,797	849,745
Financing Obligations:		
Revolving Credit Facility ($33,379 due in 2012) (4)	33,379	4,704
Total long-term debt and financing obligations	883,176	854,449
Current Portion (amount due within one year):		
Current maturities of long-term debt	(33,300)	—
Short-term borrowings under the revolving credit facility	(33,379)	(4,704)
	$816,497	$849,745

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(1) Pollution Control Bonds (“PCBs”)

The Company has four series of tax exempt unsecured PCBs in aggregate principal amount of $193.1 million. The 4.00% 2002 Series A must be remarketed in August 2012 and is shown as current maturities of long-term debt on the Company's 2011 balance sheet.

(2) Senior Notes

The Senior Notes are unsecured obligations of the Company. They were issued pursuant to bond covenants that provide limitations on the Company’s ability to enter into certain transactions. The 6.00% senior notes have an aggregate principal amount of $400.0 million and were issued in May 2005. The proceeds, net of a $2.3 million discount, were used to fund the retirement of the Company's first mortgage bonds. The Company amortizes the loss associated with a cash flow hedge recorded in accumulated other comprehensive income to earnings as interest expense over the life of the 6.00% senior notes. See Note O, "Financial Instruments and Investments - Treasury Rate Locks". This amortization is included in the effective interest rate of the 6.00% senior notes.

The 7.50% senior notes have an aggregate principal amount of $150.0 million and were issued in June 2008. The proceeds, net of a $1.3 million discount, were used to repay short-term borrowings of $44.0 million, fund capital expenditures and for other general corporate purposes.

(3) RGRT Senior Notes

On August 17, 2010, the Company and RGRT, a Texas grantor trust through which the Company finances its portion of fuel for Palo Verde, entered into a Note Purchase Agreement (the “Agreement”) with various institutional purchasers. Under the terms of the Agreement, RGRT sold to the purchasers $110 million aggregate principal amount of senior notes (the "Notes"). The Company guarantees the payment of principal and interest on the Notes. In the Company’s financial statements, the assets and liabilities of the RGRT are reported as assets and liabilities of the Company.

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

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

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

(4) Revolving Credit Facility

Prior to November 15, 2011, the Company had available a $200 million credit facility with a four-year term ending September 2014. The credit facility provided for the financing of nuclear fuel, which was accomplished through the

RGRT that borrowed under the facility to acquire and process nuclear fuel. The Company was obligated to repay the RGRT's borrowings with interest. Any amounts not borrowed by the RGRT could have been borrowed by the Company for working capital needs.

On November 15, 2011, the Company and RGRT entered into an amended and restated revolving credit agreement (the "RCF") with JP Morgan Chase Bank, N.A., as administrative agent and issuing bank, and Union Bank, N.A., as syndication agent, and various lending banks party thereto. Under the terms of the RCF, the Company and RGRT have available \$200 million of credit for a term ending September 23, 2016. The Company may request that the RCF be increased up to a total of \$300 million during the term of the RCF, subject to lender approval.

The RCF provides that amounts borrowed by the Company may be used for, among other things, working capital and general

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corporate purposes. Any amounts borrowed by RGRT may be used, among other things, to finance the acquisition and processing of nuclear fuel. Amounts borrowed by RGRT are guaranteed by the Company and the balance borrowed under the RCF is recorded as short-term borrowings on the consolidated balance sheet. The RCF is unsecured. The RCF requires compliance with certain covenants, including a total debt to capitalization ratio. The Company was in compliance with these requirements throughout 2011. As of December 31, 2011, the total amount borrowed by RGRT was $13.4 million for nuclear fuel under the RCF, and $20.0 million was outstanding under this facility for working capital and general corporate purposes. The weighted average interest rate on the RCF was 1.5% as of December 31, 2011.

As of December 31, 2011, the scheduled maturities for the next five years of long-term debt are as follows (in thousands):

2012	$33,300
2013	—
2014	—
2015	15,000
2016	—

The $33.4 million outstanding on the RCF for working capital and general corporate purposes is anticipated to be paid in 2012.

J. Income Taxes

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and liabilities at December 31, 2011 and 2010 are presented below (in thousands):

	December 31,	
	2011	2010
Deferred tax assets:		
Benefit of tax loss carryforwards	$21,737	$286
Alternative minimum tax credit carryforward	19,863	18,370
Pensions and benefits	87,946	62,821
Asset retirement obligation	20,100	33,904
Deferred fuel	—	7,317
Other	20,524	21,093
Total gross deferred tax assets	170,170	143,791
Deferred tax liabilities:		
Plant, principally due to depreciation and basis differences	(424,319)	(359,838)
Decommissioning	(22,633)	(37,936)
Deferred fuel	(2,493)	—
Other	(6,448)	(6,929)
Total gross deferred tax liabilities	(455,893)	(404,703)
Net accumulated deferred income taxes	$(285,723)	$(260,912)

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

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The Company recognized income tax expense for 2011, 2010 and 2009 as follows (in thousands):

	Years Ended December 31,		
	2011	2010	2009
Income tax expense:			
Federal:			
Current	$5,084		